NIST Special Publication 1035

Coatings for Corrosion Protection: Offshore Oil and Gas Operation Facilities, Marine Pipeline and Ship Structures

April 14-16, 2004
Biloxi, Mississippi

Edited by:

Charles Smith, Tom Siewert, Brajendra Mishra,
David Olson, and Angelique Lassiegne

Sponsored in part by:

National Institute of Standards and Technology

American Bureau of Shipping

Colorado School of Mines

Mineral Management Service

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[1] At Boulder, CO 80305
[2] Some elements at Boulder, CO

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March 2005

U.S. Department of Commerce
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National Institute of Standards and Technology Special Publication 1035
Natl. Inst. Stand. Technol. Spec. Publ. 1035, 270 pages (March 2005)
CODEN: NTNOEF

U.S. Government Printing Office
Washington: 2005

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet bookstore: gpo.gov Phone: 202-512-1800 Fax: 202-512-2250
Mail: Stop SSOP, Washington, DC 20402-0001

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Abstract

This workshop on Coatings for Corrosion Protection: Offshore Oil and Gas Operation Facilities, Marine Pipelines, Ship Structures, and Port Facilities was held on April 14-16, 2004 in Biloxi, Mississippi. This workshop of 150 attendees drew participation by internationally recognized marine coating experts, material specialists, inspection specialists, coating manufacturers, maintenance engineers, and designers. The workshop was crafted to include multiple viewpoints: industrial, academic, environmental, regulatory, standardization, and certification.

Keynote and topic papers were presented to establish a current information base for discussions. Six discussion groups addressed specific issues and identified, prioritized, and recommended specific research and development topics for the government and industries to undertake. The recommendations of this workshop offer a clear identification of research and development issues and create a roadmap for achieving them.

Keywords

coatings; corrosion protection; offshore structures; pipelines; ship structures

Executive Summary

This workshop on Coatings for Corrosion Protection: Offshore Oil and Gas Operation Facilities, Marine Pipelines, Ship Structures, and Port Facilities was held on April 14-16, 2004, in Biloxi, Mississippi. This workshop was organized by an industrial-based committee and hosted by the Colorado School of Mines for the U.S. Department of Interior (Mineral Management Service), U.S. Department of Transportation (Office of Pipeline Safety), U.S. Department of Commerce (National Institute of Standards and Technology), U.S. Department of Energy (Economic Regulatory Administration), U.S. Department of Homeland Security (U.S. Coast Guard-Ship Structure Committee), Norwegian Petroleum Directorate, California State Lands Commission, American Bureau of Shipping, Natural Resources of Canada, NACE International, and SSPC (The Society for Protective Coatings).

This workshop drew participation by internationally recognized marine coating experts, material specialists, inspection specialists, coating manufacturers, maintenance engineers, and designers. The workshop was designed to include multiple viewpoints: industrial, academic, environmental, regulatory, standardization, and certification.

Keynote and topic papers were presented to establish a current information base for discussions. Six discussion groups addressed specific issues and identified, prioritized, and recommended specific research and development topics for the government and industries to undertake. This workshop undertook a complete assessment of opportunities for research and development of coating practice, coating materials, coating application, repair, nondestructive evaluation, and extended coating life prediction. This workshop defined the state of the art, assessed the current practices and their limitations, discussed field experiences, and charted a course for the best corrosion protection methodologies of offshore structures, pipelines, and ship structures, including sensing and monitoring.

The recommendations of this workshop offer a clear identification of research and development issues and create a roadmap for achieving them. These recommendations are classified in a general fashion as Research, Development, Administration, and Operations. The recommendations are written in a format of broad agency announcement and offered in part or whole topics for consideration by agencies, technical societies, industry, and certification organizations for support and implementation.

Recommendations from the Discussion Groups

Programs
Programs consist of numerous projects which must be completed to achieve the intended goal.

Research

1. Quantitative evaluation of the long-term field performance of pipeline coatings. One project should install coated pipe samples in the field at carefully selected locations representative of different environmental conditions. Several monitoring methods should be used. In addition, the coating performance evaluation should include both consistent and fluctuating temperatures with transient and cyclic temperature fluctuations. A one-day scoping meeting prior to this investigation should be held with good representation of the interested parties.

2. Development of practices for evaluating pipeline coatings for service under extreme conditions such as: Offshore-deep sea, Offshore-Arctic, Onshore-equator is recommended. These investigations should include three types of coatings: Anti-corrosion coatings, Abrasion-resistant coatings, and Insulation coatings.

3. Development of a non-destructive method of evaluating the application of coating systems. Programs need to explore the feasibility of thermography, magnetic flux leakage, electrical impedance, and eddy current phase array. Modeling using EIS is not reliable.

4. Development of specific advancements in coating materials. A project for non-skid deck coating systems that will last when applied over less than perfect surface preparations. Parameters that control coating performance. Modeling of performance of all coatings (not only FBE). A project should include the evaluation of coatings at higher temperature in the laboratory. Performance of insulation coating should be investigated. Research project to develop coating systems that respond to exposure stresses needs to be performed.

Development

5. Improvement in the effective use of coatings for port facilities and the development of the necessary performance-based specifications. The development of generally accepted design standards and practices for port authorities needs to be established. These standards and practices need to be beneficial to the owner. Also the program needs to develop generally accepted design standards and acceptances for port facilities. This development may need to be geographically specific such as: blue water specific or brown water specific.

6. Advanced methodologies for applications of coatings. A project needs to address paint application issues without the use of brushes and rollers to increase productivity, lower costs, and less personnel exposure. The proposed investigation should include concerns of issues such as: curing time compared to burial or immersion time and adhesion of field-applied coatings to mill-applied coatings. An investigation to assess the effects of stockpiling of coating products on pipeline coatings performance including the effect of temperature, ultra-violet light, and time needs to be established. Development of high solid products, which meet VOC requirements that have less tendency to embrittle over time. Develop a mechanism to aid the painter in being able to achieve more uniform film thicknesses with high solid coatings in the field. The use of a capture device at the spray gun versus total encapsulation of the space to be painted should be investigated. Evaluate the need to increase the investment in coating application technology R&D. Establishment of a welding procedure for welding on painted surfaces is recommended.

7. Assessment of new technologies for surface preparation before coating. This program should include projects on the feasibility of using microwave technology for surface preparation, hand-held x-ray fluorescence system to detect salts on the surface, and a project to improve the dissemination and clarity of information on allowable surface chlorides. Improvement of application equipment to facilitate applying high solid coatings in the field to inaccessible areas. A project investigating the effects of minor variations in surface preparation and effects of variation in composition of surface contamination, including mill scale, on long-term coatings performance is necessary. A project on secondary surface preparation critera / Standards (example: exceeding the recoat window of an epoxy- Methodology for evaluation) needs to be established. The cost of surface preparation and coating application for underwater hull areas is going up and the designs of coating technology for this area has not kept pace.

Administration

8. Standardized methodology for data collection and management. An unbiased third party to compile an industry wide historical data base on pipeline coating performance and evaluate the data critically needs to be established and funded. A program to establish user-friendly standardization needs to be initiated and performed. The program would include a project on the standard/ recommended practices for implementation of inspection for protective coatings projects.

9. Formulation of a roadmap for coatings research and/or development that indicates the proper sequence of projects. The roadmap needs to be periodically updated by industrial organizations as well as government research agencies and industrial users of coated structures. Such a roadmap would be helpful in prioritizing national and international needs and to assist in obtaining the necessary funding. The roadmap program will need to be annually updated by NACE International and SSPC (The Society for Protective Coatings).

10. A working group, national or regional, to increase exchange of information on the performance of coating products and application. The working group can formulate through user conscience new performance based specifications, design standards, and practices for port facilities. There already exists the working structure for such a working group in the existing coating and corrosion societies. It needs an initiator. (Note: Loosely exists at SSPC).

11. Evaluation of the economic issues of coating materials, their application, and their service behavior. A specific project on the study of the measurable economic contribution of the inspection of coatings project successes and performance needs to be performed. A project to study economics of coating technology to suggest and recommend the most cost effective use of the present technology should be implemented. The issue is that use and deployment of new coating technology is hampered by high cost of new equipment. Look into what can be done to utilize existing equipment; lower the cost of new equipment; or provide the financial incentives needed. Consumer and coating industry feedback loop needs to be improved. Problems are generally reported and investigated; however, successful applications rarely are investigated to confirm good practice.

Operations

12. Advanced methods for coating repair. This program should include a project on standards for quantification of performance and repair criteria and a project to quantify the effect of "repairs" on newly installed coatings system's performance.

13. Training, education, and certification of painters, corrosion engineers, and inspectors in the marine and pipeline industry. Develop a certification and training program for painters in the marine industry. Help develop an engineering technologist degree / vocational training program for coating specification. Guidelines/Practices/Standards for evaluating In-Service Coatings and the training of Coating Survey Inspectors, with focus on Inspection and Evaluation of In-Service Coatings and tools for evaluation needs to be organized. A special program for educating Coast Guard and MMS inspectors to establish consistency with the offshore industrial standards. Development of a hiring program offering training and certification plus weekly pay, which would have an impact on safety, employee morale, and salary.

14. Development of coating/corrosion assessment criteria and acceptable corrosion levels for use by corrosion engineers and regulators in the development and assessment of Asset Integrity Management Programs. Development of a criteria for determining the most cost effective maintenance effort and tools to quantify: coatings age and degradation, ability to apply over-coatings, and consistent evaluation needs to be established.

15. Address the environmental and health and safety issues regarding paint materials and their application. A project for the determination of the effects of environmental conditions and variations in coating procedures on the performance of field-applied pipeline coatings needs to be instituted. A project on the development and research of environment tolerant coatings that can be used year round with increased quality. The development of pipeline coatings with anti-microbial properties. This development must achieve coating acceptable ecological concerns.

Organizational Committee

An organizational committee of recognized experts in coating technology and marine structural integrity was established to assist and advise the principal organizers on the final format of the workshop. They also recommended speakers, committee co-chairpersons, and authors for the various papers (keynote, theme, and white). The papers' authors and speakers were carefully chosen from those who have recently contributed to the technical literature (especially the state of the art in marine coating technology), based on industrial experience.

- Angelique Lasseigne: CSM
- Bernard Appleman: KTA-Tator/SSPC
- Betty Felber: U.S. DOE-Tulsa
- Brajendra Mishra: CSM
- Charles Smith: MMS
- David Olson: CSM
- David Shifler: NAVSEA
- Diana Diettrich: ABS
- Doug Moore: Carboline
- Garrett Atkins: Exxon
- George Wang: ABS
- Helena Alexander: NACE
- Howard Mitschke: Shell Global
- Jack Spencer: ABS
- James Merritt: DOT-OPS
- James Phipps: ABS Consulting, UK
- Joel McMinn: Chevron-Texaco
- Kirk Brownlee: STRESS, INC.
- Louis Sumbry: BP-Amoco
- Pat Fallwell: ABS
- Robert Rogers: Exxonmobil
- Robert W. Smith: DOT-OPS
- Ron Scrivner: Transcon. Pipeline
- Tom Siewert: NIST
- Winston Revie: NRC-Canada
- Wm. Michael Drake: LANL

Sponsors

The sponsors of the workshop were:

- American Bureau of Shipping
- California State Lands Commission
- Colorado School of Mines
- MADCON Corporation
- NACE International
- National Institute of Standards and Technology
- Natural Resources Canada
- Norwegian Petroleum Directorate
- SSPC
- Trenton Corporation
- US Coast Guard – Ship Structure Committee
- U.S. Department of Energy
- U.S. Department of Interior-Minerals Management Service
- U.S. Department of Transportation – Office of Pipeline Safety

Introduction

The Colorado School of Mines organized an International Workshop on Advanced Research and Development of Coatings for Corrosion Protection of Offshore Oil and Gas Operation Facilities, Marine Pipelines, and Ship Structures, with specific emphasis on Life of Coating, Materials, Repair of Coatings and NDE. The workshop was primarily sponsored by the Minerals Management Service of the U.S. Department of Interior. In addition, the workshop was co-sponsored by the U.S. Department of Energy, American Bureau of Shipping, National Institute of Standards and Technology, National Association of Corrosion Engineers-- International, and other private companies. The workshop was held in Biloxi, Mississippi from April 14-16, 2004. The sponsors recognize that new technologies for remotely sensing and monitoring the corrosion damage of coated structures are important in guaranteeing structural integrity.

This workshop was undertaken to completely assess the opportunities for research and development to enhance coating practices, coating materials, application, repair, nondestructive evaluation, and coating life prediction. The workshop defined the state of the art, assessed the current practices and its limitations, discussed field experiences and charted a course for the best corrosion protection methodologies of offshore structures, pipelines, and ship structures, including sensing and monitoring. This workshop was designed to clearly identify the research and development issues and to chart a course for achieving them. The workshop achieved its objectives.

Internationally recognized marine coating experts, material specialists, inspection specialists, coating manufacturers, maintenance engineers, and designers participated in the deliberations. Industrial, university, environmental, regulatory, standardization and certification leaders provided a breadth of knowledge and experience to the endeavor. This book presents an archival record of the workshop proceedings.

The best forum for an assessment and R&D path determination as the one described above is a dynamic workshop. An advanced coating workshop is a very cost-effective method to: (1) transfer information, (2) learn about new technologies and materials, (3) assess future needs, and (4) define the best opportunities for research. New technologies for remotely sensing and monitoring the corrosion damage of coated structures are important to guarantee integrity.

The Opportunity: The marine environment is particularly aggressive, and all marine vessels and offshore structures need protection from corrosion. The selection of the coating system depends on the location of its application, such as the hull, waterline area, topsides, decks, interior, and tanks, etc. Owing to their low cost, availability, and ease of application, paints and coatings have been the

preferred method of topside protection. Advances in zinc, polyurethane and powder coating technologies make them a superior alternative to epoxy resin technology for longer-term service life. Zinc provides cathodic protection as thin coatings, polyurethane is effective and aesthetically appealing, while powder coatings can meet the environmental and regulatory challenges. The present need for marine coatings go beyond performance, as they are required to comply with various environmental regulations.[1]

Much progress has been made in the practice of using coating technology to offer corrosion protection to offshore structures, inner-hull tanks in fuel tankers, ship hulls, underwater pipes, etc. New methods have been developed to repair and protect concrete and steel structures in coastal and offshore waters, such as the all-polymer encapsulation technique to repair and protect structures in the splash zone.[2] But the fact still remains that there is demand from the engineering community responsible for integrity of offshore structures, ship hulls, inner hull compartments, and pipelines for significant advancements to the present long-life coatings. When designing any structure for service in an aggressive offshore environment, undesirable outcomes (such as overdesign, structural failure, costly and inadequate maintenance, product loss, production downtime and inefficiency) will likely occur, unless they are considered during the design process.[3] Long-term structural or mechanical requirements for a particular application can be assured through corrosion protection, through either coatings or a combination of cathodic protection and coatings.

Advances in coating technology can offer significant cost saving if developed and successfully demonstrated. This coating workshop has allowed technological transfer of new coating approaches to offshore platform and pipeline operators and designers. This workshop has also permitted a thorough assessment of the state of the practice and identified the best pathway to extend the life of coatings, and thus coated structures.

The workshop objectives were

1. To discuss the effectiveness of various coating materials and practices,
2. To identify both the technical and non-technical hindrances to the application of new coating materials and practices,
3. To identify the research activities that can significantly improve coating materials, application, inspection and estimation of service life, and thus deserve support,
4. To provide an international forum, attracting participants from all aspects of coating use and repair (corporate leadership, coating material manufacturers, designers, maintenance engineers, inspectors, coating engineers and leading contributing scientists),

5. To promote the use of cost-effective advanced coating methods for marine structures, and
6. To produce an archival record (planned to be a hardbound book), which thoroughly describes both the current coating technology and practices and identify opportunities for potential advancements for coated marine structures.

A careful balance of (1) presentations on current status of marine coating technology at the research and production levels, (2) position white papers for working group discussions on specific coating materials, method of application, regulations, assessment of coating service life and inspection issues, and (3) identification of the educational, research, and development needs regarding advancement in coating materials, coating application and nondestructive evaluation technologies for marine structures were included in the workshop program and is reflected in this proceeding.

The attendees were divided into discussion groups on:

1. Coatings for ships,
2. Coatings for offshore structures,
3. Coatings for pipelines,
4. Coatings for port facilities,
5. Coating materials and deposition technologies, and
6. Coatings inspection and repair.

In addition, eight theme papers were presented on

1. **Environment, health and safety:** training, waste disposal, blasting, anti-fouling;
2. **Tankers and FPSOs corrosion:** double and single hulls, operations of tankers and FPSOs, ballast tanks, fixed and floating structures;
3. **Inspection and repair:** coating on existing structures, new techniques and standards, third-party versus contract inspection;
4. **Ensuring coating performance**: roles and responsibilities for coating systems: paint manufacturers, contractors, inspectors, owners, coating warranty;
5. **Emerging technologies in:** progress in other relevant industries (navy, space, etc.), academia. Materials, anodes, high-temperature coating, composite, NDT, smart coatings, implementation of new techniques;
6. **Risk assessment and economic issues:** lifetime prediction, failure modes, condition surveys, RBI, integrity management;

7. **Decision making in coatings selections:** new structure, qualification and associated procedures; and
8. **Corrosion protection in pipelines:** internal and external, insulation coating, weight coating, corrosion protection coating, and efficiencies in coating.

Section 1

Welcoming Remarks

Charles Schoennagel
Deputy Regional Director
Gulf of Mexico OCS Region
Minerals Management Service

On behalf of the Minerals Management Service, I would like to add my welcome to all of you here for this workshop on coatings for corrosion protection of offshore oil and gas facilities and pipelines. I can see by the number and diversity of the participants as well as by the broad breadth of topics on the agenda that this workshop will be a success.

I want to extend a special welcome to our colleagues from abroad whose participation truly makes this an international event.

I would also like to thank the organizers of the workshop, especially Dr. David Olson and Dr. Brajendra Mishra as well as other members of the staff from the Colorado School of Mines. A very special word of thanks should also go to the members of the joint government-industry steering committee for their time and efforts in preparing the workshop program. And lastly, a special word of appreciation to the many other co-sponsors, whose names you'll find on the front of the workshop program.

As most of you know, the Minerals Management Service, or MMS, regulates offshore oil and gas operations on the United States Outer Continental Shelf (OCS).

Not as well known is that MMS also collects lease bonuses, rents and royalties due the U.S. Government for minerals production from Federal and Indian lands, both onshore and offshore. On average, more than $6 billion per year is collected and distributed making us the second largest revenue collection agency in the U.S. Government. Of this, approximately $5 billion comes from OCS operations.

The OCS makes a significant contribution to the nation's energy supply, providing approximately 30 percent of the oil and 23 percent of the natural gas produced in the U.S. On a per-day basis, the OCS currently produces about 13.5 billion cubic feet of natural gas and about 1.7 million barrels of oil.

The MMS has responsibility for all aspects of minerals development from the initial leasing of offshore acreage, through the oversight of exploration and development operations, to the point at which platforms are decommissioned. A critical focus of our regulatory program is ensuring a high level of safety and environmental performance during all phases of OCS activity.
I thought that it would be of interest, since the OCS is responsible for 30 percent of the U.S. domestic oil production, to see what the trend has been for the past

few years. As seen in Figure 1 there has been a continued drop in all other domestic sources, which include production from all federal onshore lands as well as state waters. However in the early 1990's, as a result of deepwater developments, the OCS production has seen a fairly steady increase.

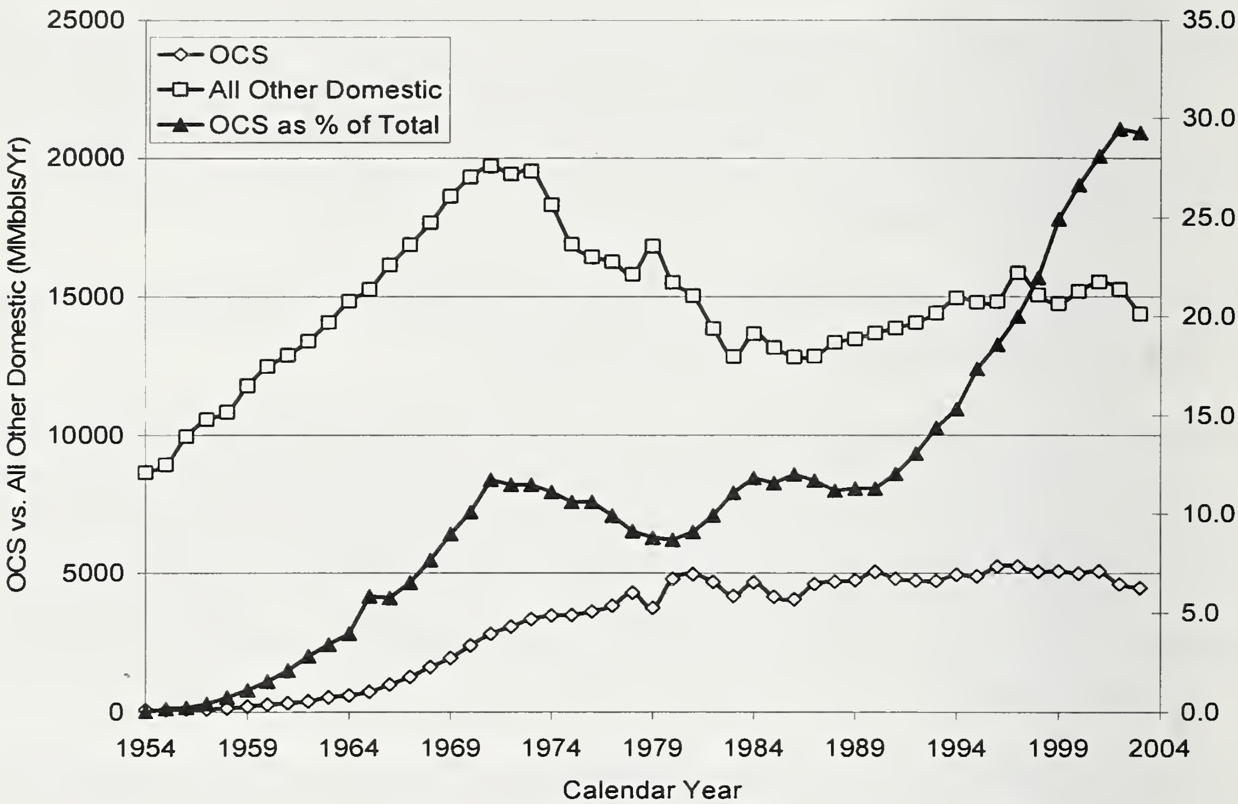

Figure 1 - Crude oil and condensate production from the Outer Continental Shelf (OCS) compared to all other domestic oil production

For natural gas, for both OCS and other domestic sites, the total production has been pretty steady since the mid 1980's and the percentage from the OCS has been somewhat constant (Figure 2). We hope that with new deepwater developments and the renewed interest in the deep gas plays in the GOM that the OCS production will rise in the next few years.

Deepwater oil and gas developments in the Gulf have continued to be the work-horse of U.S. domestic oil and gas production. In 2000, a major milestone was achieved, for the first time more oil was produced from water depths sites, defined as greater than 1,000 ft, than from shallower waters of the Gulf of Mexico (GOM). Currently, of the total production from the OCS, approximately 60 percent of the oil and 25 percent of the natural gas is produced from deepwater sites.

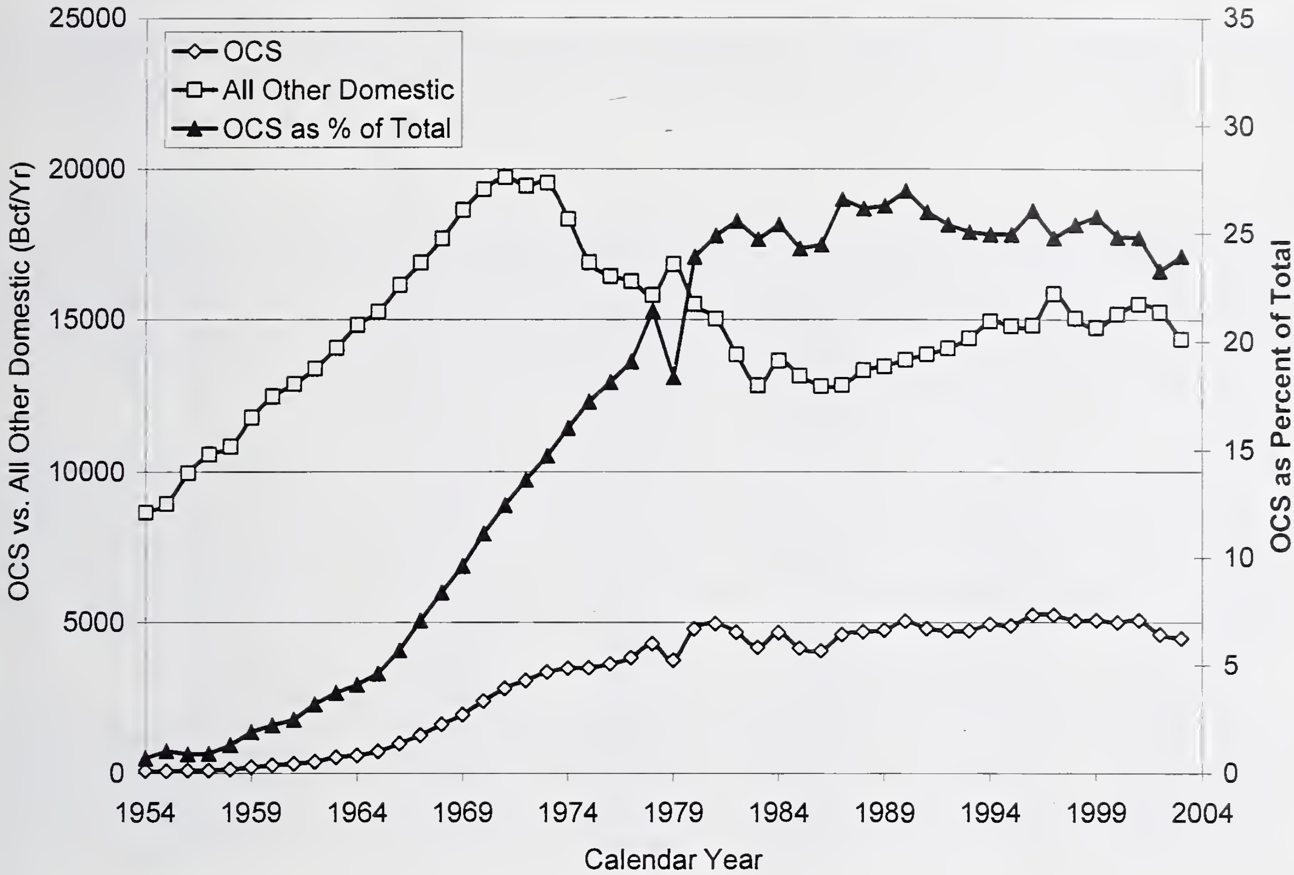

Figure 2 - Natural gas production from the Outer Continental Shelf (OCS) compared to all other domestic oil production

The U.S. is now in its tenth year of sustained expansion of domestic oil and gas developments in the deepwater areas of the Gulf of Mexico, and it shows no sign of diminishment. This resource potential for the nation continues to grow with each new discovery in ultra-deepwater.

For oil and gas producers, operating in deepwater has brought continued prosperity, but also new challenges. Producers are constantly pushing logistical and technological limits. New solutions are constantly being demanded to meet these challenges in order to further an excellent operational record. For instance, there were five announced discoveries in 5,000 ft of water or greater in 2001, three in 2002, and six in 2003 and this year for the first time, 12 rigs are drilling for oil and gas in 5,000 feet of water or greater.

Industry continues to operate and conduct exploration drilling in the shallow-water areas of the Gulf of Mexico. The new exploration has been focused on finding new oil and natural gas resources that are being identified by new technology and/or geophysical data interpellations.

Also the deep gas plays in the shallow waters of the GOM are being developed where drilling is being conducted from existing wells to depth between 15,000 to 25,000 feet.

As these platforms and pipelines continue to age, MMS is increasingly concerned with the means to ensure the integrity of these older facilities and is working with the industry on means available to conduct integrity assessments.

Aging or damaged offshore facilities present many challenges to the offshore industry and regulators worldwide. Currently, over 6,500 platforms and associated pipelines are operating in some 50 countries. These facilities are of various sizes, shapes, and degrees of complexity, some being installed in the 1950's and many operating well beyond their intended service life.

Many of these existing facilities were designed in accordance with lower standards than are currently prescribed. Others have suffered damage as a result of storms or accidents or, because of the lack of active maintenance programs have deteriorated to the extent that their future structural integrity is in question.

Addressing issues related to inspection, maintenance and the repair of platforms and pipelines is not new to the offshore industry. However, the growing number of aging facilities, their share of the total production, their perceived vulnerability as well as the high cost of replacement have focused attention on their integrity and the need to develop acceptable maintenance guidelines.

For example, in the Gulf of Mexico we have approximately 4000 platforms. The total platform population continues to rise as we have about 140 new installations per year with about 125 removals per year. The MMS receives reports on about 800 underwater facility inspections a year and up to 4000 topside and cathodic protection inspections per year.

To put things into a little more perspective, I would like to note some of the statistics on the facilities in the Gulf of Mexico.

As shown in Figure 3, the average age of existing facilities in the GOM is 20 years, a figure which was often used to derive the “design life” of most of them. It is also interesting to note that 25 percent are 30 years old or older. In fact 10 percent are older than 40 years of age. Of the total number of fixed facilities over 65 percent are in water depths less than 100 feet and what may be considered more surprising, 95 percent are in water depths less than 300 feet

Of the total number of fixed structures, 40 percent are steel caissons or well-head platforms and the remaining 60 percent are steel jacket structures.

A large percentage of the facilities are well maintained, however a few are not. In the lean years, and with the high cost of deepwater exploration and development, for some companies the maintenance of the existing older facilities was not a high priority.

Since this is a workshop on coatings for corrosion protection, I would like focus on the concerns that we have within the offshore oil and gas community.

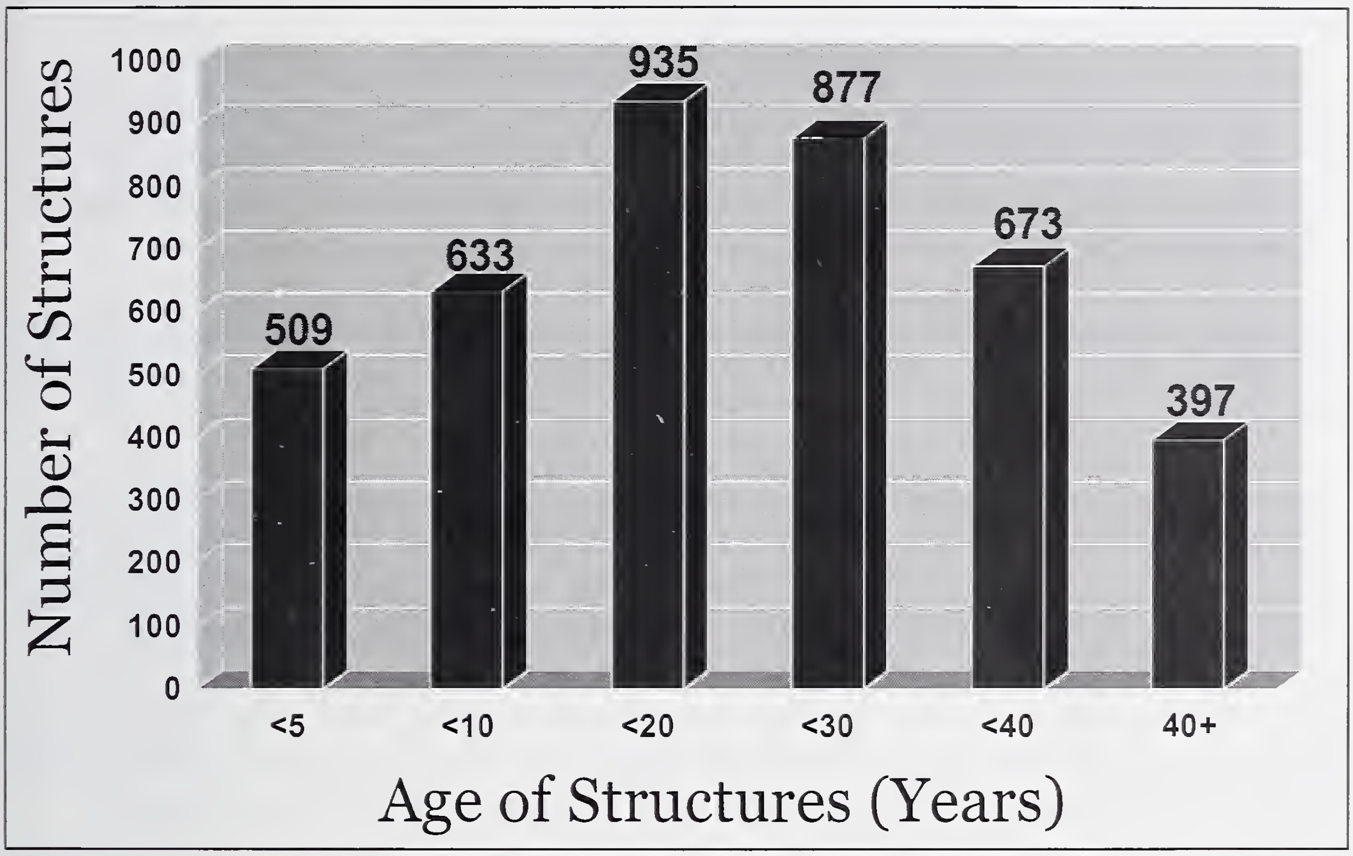

Figure 3 – Age of existing facilities in the Gulf of Mexico

Not all platforms on the OCS show a lack of maintenance, but some do. I do not think anyone would question the structural integrity of facilities with corrosion damage to such an extent that holes existed in members and or that members were missing.

Damage is not limited to the steel jackets. Corrosion and lack of maintenance occurs on the topside support elements, gratings, hand rails, stairs, pipe grads and other elements if not protected. Also, both pipelines and risers are prime targets for corrosion. Our inspectors see all types of corrosion and lack of corrosion protection or coatings on offshore components.

Again, the lack of maintenance and corrosion on risers and other structural elements can have serious integrity implications. The MMS has taken several steps to work with the industry to address integrity concerns relative to corrosion.

An inspection grading system for the coating systems has been added to the annual Office of Structural and Technical Support (OSTS) report required by the MMS. It is composed of three grades reflecting the coating condition:

A = Good condition – no maintenance needed in 3 years
B = Fair condition – maintenance required in 3 years
C = Poor condition – maintenance needed in 12 months

For facilities in poor condition, the MMS will discuss mitigation measures with the operator during their annual performance review.

We are also in the process of rewriting Subpart I, Platforms and Structures, to include relative standards from the National Association of Corrosion Engineers (NACE) and will maintain photos of relevant facilities in our TIMS database for future reference.

We have taken an active role in sponsoring workshops such as this to address the issues and to seek solutions to include hiring additional structural engineers to work the problem.

As I have previously stated, oil and natural gas derived from the OCS are major resources in meeting the energy needs of the nation and its role will only continue to expand in the future. The base of existing facilities and associated infrastructure are keys to this expansion and we must maintain their integrity.

We in MMS believe there is tremendous benefit from collaboration between the industry and regulator and are working together to ensure that each party's goals are met. That is why we are here – to learn together and plan for the future.

Bud Danenberger of the MMS stated in his opening remarks for the Corrosion Workshop that was held in Galveston in 1999 that "There's no corrosion crisis. We have a number of concerns, but there's no crisis." This is still true. Corrosion is the leading cause of pipeline failures and is of growing concern relative to the aging fleet of platforms. And when you have facilities with corrosion problems, there is the potential for a serious incident and associated economical impacts.

In closing, let me note that the MMS fully supports this effort and encourages everyone here to actively participate so that the workshop will generate useful guidance for future standards or research.

We look forward to the discussions and interchange of opinions over the next several days, and particular to the conclusions and direction that the workshop will provide in the area of coatings for offshore and marine structures. These will undoubtedly be a great value to the offshore and marine industry and to other industries as well.

Again, I would like to thank Dr. Olson and the steering committee for organizing this workshop and the many co-sponsors for their support as well as your participation.

It has been a pleasure to speak to you this morning, to share our enthusiasm for this workshop and to briefly describes MMS's interests and desires for improvements in coatings for corrosion protection.

James Card
Senior Vice President, American Bureau of Shipping
USCG Vice Admiral (ret.)

On behalf of the American Bureau of Shipping, I would like to welcome all of you here for this international workshop on Advanced Research & Development of Coatings for Corrosion Protection. My thanks to Prof. Olson and the Colorado School of Mines for organizing this workshop, and for inviting me to speak before this distinguished group.

As you are probably aware, the American Bureau of Shipping is a leading worldwide classification society. Its mission is to promote the security of life and property at sea, and protection of the natural environment. ABS does this by setting standards for design, construction and operation for shipping and offshore industries. These standards also include survey of structural conditions through out the life of the vessels. As coatings are a key preventative measure for deterioration of steel structures, ABS is keenly interested in the topics under discussion at the Workshop.

We look forward to the discussions and interchange of opinion over the next several days, and particularly to the recommendations and direction that the Workshop will provide for the marine and offshore industry.

Corrosion

It was recently estimated (in a NACE report) that the average cost of corrosion protection due to new ship construction is $7.5 billion per year. This equates to approximately seven to ten percent of the cost of the vessel, with chemical tankers as high as thirty percent. The annual cost for repair and maintenance due to corrosion was estimated at $5.4 billion with an additional $5.2 billion cost associated with downtime.

Vessels continue to be constructed of steel, but now probably less steel due to analytical ability to optimize deigns. Tankers are now required to be constructed with double hulls, introducing changes to operating conditions in ballast tanks. There have been dramatic offshore advances into deep water. FPSO's are being installed with expectations of remaining on location for twenty plus years. How has the state of the art in corrosion protection faired along side these design and operational advances?

Coating and Classification Surveys

Traditionally, classification has required all steel work to be suitably coated with paint or an equivalent. Certain areas are required to be protected with an epoxy type coating including salt-water ballast tanks and cargo holds of bulk carriers. Is there a need to extend this to cargo tanks? This topic is currently being debated.

Coatings are necessary but who is responsible for establishing the minimum or recommended standards: the coating manufacturer, the shipyard, or the owner? There are various schemes in effect and available now. Some class societies offer optional notations to cover coatings. These range from the approval of coating only as meeting a specification to full involvement with the application of the coating. Recent SOLAS regulations require submittal of documentation on the scheme for the selection, application and maintenance of the coating system. How can interested parties be assured appropriate coatings are applied for a given situation?

ABS provides guidance for grading the condition of coatings in the Guidance Notes on the Application and Maintenance of Marine Coating Systems. These Guidance Notes, developed by an ad hoc panel of coating experts from manufactures to vessel operators, contains over fifty pictures of coatings with their assigned condition grade. Is this system of grading coating condition the best available? Is there more advanced technology that could be used?

In the case of salt-water ballast tanks, class judges the condition of the coating (good, fair, poor) as a basis for subsequent classifications examinations. Coatings of salt-water ballast tanks found in less than Good condition for tankers subject to Enhanced Survey Program require annual examination of the tank. “Good” is defined as a condition with only minor spot rusting. What constitutes satisfactory repair of the coating back to a “Good” condition?

Expectations of the Workshop

The need for coating and corrosion protection is evident. We need to understand the practical issues of today and be open to identify tomorrow’s issues with both corrosion science and coatings technology. Workshops like this are a venue for cross industry discussions that can lead to understanding and identification of the solutions.

I would like to challenge all of you to consider these three very practical issues:

- How can the marine industry best determine what areas coatings should protect?
- How can interested parties be assured appropriate coatings are applied for a given situation?
- How can operators be assured that the applied coating performs in a satisfactory manner?

The American Bureau of Shipping fully supports the ongoing efforts in coating design, manufacturing, application, and continued discussions of these topics. ABS encourages everyone here to actively participate, so that these workshops will develop useful guidance for the direction of application, inspection and future research. The commercial marine sector will benefit greatly with the advancement and collation of coating technology.

It has been a pleasure to speak before you this morning to share our enthusiasm for this workshop, and to briefly describe ABS' interest, experience, and desired improvements.

Larry Christie

NACE INTERNATIONAL
THE CORROSION SOCIETY

NACE International, The Corrosion Society, welcomes you to this important event on Coatings for Corrosion Protection. NACE is a technical society that serves as a clearinghouse for information on all forms of corrosion control. We also recognize that coatings technology is the number one method employed worldwide to protect all structures from corrosion, from offshore structures, to pipelines, to ships and beyond.

My name is Larry Christie, and I began working at NACE two weeks ago as the " Coatings Market Manager ", a new position created by NACE because it recognized the need to more thoroughly integrate coatings technologies into all activities throughout NACE. Since sixty percent of NACE's 15,000 members report that they have some level of responsibility with coatings work, I appreciate being able to participate in a conference like this one. As a side note, the NACE past president and current interim Executive Director, Pierre Crevolin, could not be here since he now works for NACE in Houston, and went home to Canada for the Easter holiday. On Monday, U.S. Customs decided that if Pierre is not being paid for engineering work by the hour in Houston, then his work visa is invalid and he was not allowed to return to NACE in Houston, or to Biloxi for this conference. I am a fellow Canadian of Pierre's and obviously we have not figured out how NAFTA applies to us.

To begin, I would like to help quantify the importance of the coatings industry in the U.S. by sharing some facts. NACE recently completed a Cost of Corrosion Study with funding from the Federal Highways Administration, which concluded that corrosion costs the U.S. $276 billion a year and yes, that was $276 billion, which is equal to 3.1 percent of the US Gross Domestic Product. More astounding was the role of coatings in preventing corrosion. There are many technologies -- coatings, cathodic protection, materials design, chemical inhibition, etc., to help reduce the affects of corrosion. The Cost of Corrosion Study said that the cost of these services totals about $121 billion per year. Of that, however, $108 billion dollars, or eighty-nine percent of the money being spent today to help prevent corrosion is in the coatings service sector.

Obviously, then, the pressure is on the coatings industry to make advances in technologies that are reflected in lower overall costs related to corrosion. By helping to organize events such as this with the Colorado School of Mines, the MMS, and the American Bureau of Shipping, NACE hopes to facilitate cross-fertilization of ideas and the dissemination of information that will lower the cost of corrosion in the future. In fact, it is not just our hope, it is our mission and a key element in our strategic plan. As I noted before, NACE feels so strongly about the importance of the coatings industry to its mission that it recently added a Coatings Market Manager (me) to its staff to provide specific direction and focus to these efforts.

nd what else did the Cost of Corrosion Study tell us? It said that achieving the most ffective corrosion control strategies still requires widespread changes in industry nanagement and government policies and additional advances in science and technology. hese needed changes directly correlate to the purpose of this event here in Biloxi; we hope nat in five to ten years, the next Cost of Corrosion Study will show that technical conferences ke this one have had a positive impact on our ability to reduce the cost of corrosion overall.

he preventative strategies recommended in the Cost of Corrosion Study will certainly be dvanced by your activities this week. The preventative strategies are to:

1. Increase awareness of large corrosion costs, and potential savings
2. Change the misperception that nothing can be done about corrosion
3. Change policies, standards, regulations, and management practices to increase corrosion savings
4. Improve education and training of staff

he papers that you will discuss and debate this week also address the study's technical reventative strategies:

1. Advance design practices for better corrosion management
2. Advance life prediction and performance assessment methods
3. Advance corrosion technology through research, development, and implementation

he Cost of Corrosion Study really has highlighted the role of coatings in protecting assets nd reducing expenses related to corrosion. NACE supports events such as this one ecause everyone here has to work together to generate ideas and share information that vill reduce the affects of corrosion. Finally, as an industry, the corrosion control profession as to do better at using its talent to make both short- and long-term impacts on the reservation of assets and the environment. We know that this lively and energetic forum will ertainly work toward that goal.

he conference organizers have asked us to make remarks on why a conference like this is o important to our organizations -- in this case, to NACE. That's easy. Every industry eeds leaders. And conferences such as this one are where the leading is done. You lready know that this conference is focused on progress, on change, and on moving forward o new and improved technologies. The workshops that you participate in this week are tructured to encourage debate and stimulate forward thinking. I hope each of you will share our ideas openly, candidly, and enthusiastically while participating in these workshops. The esulting industry papers, at the end of the week, may be more valuable to industry than any ther papers from recent events.

nother reason that this conference is so important is that it facilitates cross-fertilization of deas. Many of you are from different industries such as: shipping, pipeline, offshore, and thers. Like NACE, this conference places value on helping you to see what technologies

and techniques other industries are using that could be applied in your industry. There are many smaller conferences that you might attend that include only your colleagues in your industry, and they also have their purpose. We hope that you will take some time this week to listen to what others are doing and reflect on how you might take advantage of what you learn from them.

While I am here, I also wish to make a plug for the new NACE Foundation. All of you are here at this event to learn more about technologies that can help you in your job or your career. Two years ago, NACE endeavored to increase the stature of the coatings industry and other corrosion control industries by establishing the NACE Foundation. Its mission is to excite students and the public about what you do, so that the public is more aware of the importance of your work, and so that young students are more likely to seek career paths in our industries. Please drop by the NACE booth to see the Foundation's new NACE Inspector Protector Storybook and take one of these booklets home to your kids to show them what you do! Maybe they will start calling you Inspector Protector, Super Coat, Smart Pig, Captain Cathode, or one of our other corrosion heroes. Hopefully they won't call you one of the villains like Count Corrosion or Dr. Forbidden.

Again, I wish to thank the Colorado School of Mines for asking NACE to participate and for doing such an excellent job with this technical program, and on behalf of NACE I welcome you to this conference and hope that you find the program to be intellectually challenging and productive. Thank you.

Section 2

Keynote Addresses

Research & Development of Coatings for Alaska Tanker Company

Jack Thibault
Engineering Team Leader
Alaska Tanker Company, LLC

When ATC was approached several months ago and asked if we were interested in presenting at this conference, our response was immediate and affirmative. In today's maritime world of strict regulatory control, the strong emphasis on vessel condition and the ever present focus on efficiency, have forced operating companies such as ATC to make difficult decisions on vessel retirement and investment protocol for new construction.

To better explain ATC's position in this regard, allow me to first set the stage by summarizing our company's history and operating philosophy.

ATC was formed in April of 1999. Our company's charter limits us to the carriage of Alaskan hydrocarbons--primarily North Slope Crude Oil. We presently operate a fleet of eight vessels and are the largest transporter of ANS crude in the Trans-Alaskan Pipeline trade.

ATC's combined Health, Safety and Environmental (HSE) performance excels or is at least on par with any major shipping company in the world. During 2002 and 2003, ATC transported 311 million barrels of crude oil with less than three total gallons of oil (from any source) being spilled to sea ANYWHERE. ATC has completed five million man-hours without a Lost Time Injury. The Loss Time Injury frequency rate has been zero for both 2002 and 2003, and the 12-month total recordable injury frequency rate has fallen to 0.54 as of December 2003.

ATC has been recognized for its superior performance by the Alaska State Legislature, the Prince William Sound Regional Citizens Advisory Council (RCAC) and the Washington State Department of Ecology. ATC is one of the few shipping company's worldwide to be SQE certified by the American Bureau of Shipping (ISM, ISO 9002, and ISO 14,000).

At ATC, we believe our HSE performance culture and our proactive HSE programs lead to sound preventative maintenance practices that help to deliver fiscal performance. In the course of delivering outstanding HSE performance, we have reduced our total operating budget by fifteen percent, since our company's inception.

Since the passage of the Oil Pollution Act of 1990, vessels operating in the Trans-Alaskan Pipeline Trade have become one of the most scrutinized fleets presently operating in the world. Our vessels are removed from service 26 days of every year to complete a thorough structural examination of the vessel's entire

cargo block. On average, the cost to complete this examination and subsequent repair is approximately $500,000.

Internationally, recent marine casualties have further toughened the inspection criteria of all vessels, especially vessels operating in the tanker trade. New Classification Society Rules with respect to close-up examination and the grading parameters of existing coating systems could effectively result in the early retirement of vessels that would previously have continued in service.

As a result of increasing awareness of the risk inherent to the Oil Majors brought by the carriage of oil at sea, most of the Majors have implemented a vessel inspection system independent of regulatory and statutory entities. These inspections, known as vettings, are independently ordered by the Oil Majors prior to acceptance of the vessel for the carriage of their oil. The vettings adhere to the standards of the Ship Inspection Report Program (SIRE), a system developed by the OCIMF (Oil Companies International Marine Forum) in 1993 to address concerns of the Oil Majors with respect to the chartering of sub-standard vessels.

SIRE requires that the inspectors use a uniform inspection protocol. The results of these inspections are then made available to all program participants. All of the oil majors use the information kept in the SIRE database to determine if the vessel candidate exposes the Oil Major to unacceptable risk.

The complexities of operating an aging fleet while meeting all SIRE Program requirements has forced ATC to make major policy decisions about how we will conduct business.

As a partial result of inspection criteria set forth in SIRE, ATC decided that no company-operated vessel would continue in service with known areas of substantial corrosion. Simply defined, substantial corrosion is wastage in excess of 75 percent of the allowable margin but still within acceptable limits for continued service.

ATC also implemented a policy of repairing any structural defect, including the repair of any fracture to any structural member one-half inch (12 mm) in length or longer.

Prolonged structural integrity is directly connected to the coating system selected for each vessel dependent on the vessel's trade. The average cost of grit blasting and re-coating one set of double bottoms on one of our 120,000 DWT tankers in the United States is approximately $1.2 million.

Recent changes by Classification Societies concerning the grading of ballast tank coatings have essentially created only two grades, good and poor. While the fair coating condition grade still exists, tanks receiving this grade are required to be

internally examined annually, resulting in costly out-of-service time for the vessel. More importantly, this item will be seen on vetting reports, which could make the vessel less attractive from a chartering perspective.

Technological improvements in repairing existing coating systems have become an operational necessity. We have not completed a drydocking since 2002 where some form of coating repair or complete recoating of a ballast tank has not been required.

For vessels constructed with reduced scantlings, it is mandatory that coating systems be adequately maintained. If additional thickness measurements are required where substantial corrosion is found, the results will be evaluated on the scantlings prior to the reduction.

A Condition Assessment Survey as completed by, in our case, the American Bureau of Shipping, is a complete evaluation of a vessel's machinery, structure, and associated equipment. This Survey is requested by the Owner/Operator, and is independent of Class Surveys. The Survey assigns a grade to the ship:

- Grade 1: Vessel is considered good in all respects.
- Grade 2: Vessel is considered satisfactory, being well-maintained with only minor deficiencies.
- Grade 3: Vessel is considered below average. Though still serviceable, may require short-term corrective action.
- Grade 4: Vessel is unsatisfactory, in need of immediate corrective action.

Many of the Oil Majors require vessels deemed acceptable for charter to maintain a Condition assessment of Grade 2 or better.

To better illustrate the commercial and operational impacts in today's marketplace concerning vessel condition, I would like to discuss the life-stories of two particular vessels.

The first vessel was the ST Prince William Sound. She was built as the first of a newly intended Double Hull Ecology Class Tanker. At construction, none of the vessel's wing, double-bottom or peak ballast tanks were coated.

By 1990, a significant amount of steel renewals were required in way of the inner bottom tank top plating. To arrest further corrosion, all saltwater ballast tanks were hard epoxy coated during this repair period. The coating materials that were applied, the surface preparation, the method of application and the actual diminution of strength of the members at the time of re-coating are not known to us, but have played an important role in the subsequent life of the vessel.

In 1994, a re-coating program had been commenced as the coating system applied in 1990 had already begun to fail. As the re-coating program continued

through subsequent drydockings, the amount of steel renewals required continued to increase. During drydockings in 1996, 1998, and 2000, approximately 250 metric tons of steel required renewal. Upon leaving the drydock in 2000, the vessel had approximately 125 tons of steel identified as having substantial corrosion.

In January 2002, a SIRE vetting was completed on the vessel. Noted in the vetting report was the fact that the vessel had an additional 125 tons of substantially corroded steel. Even though the vessel was built "Over Scantling" and the level of corrosion was not to the point of requiring renewal by Class, it became apparent the vessel was in jeopardy of not being acceptable for charter. It was at this point that ATC adopted its position on substantial corrosion.

Over the course of the next 12 months, ATC undertook the project of evaluating the structural health of the vessel. Nearly 100,000 ultrasonic thickness measurements were taken. At the request of ATC, ABS commenced a SafeHull Condition Assessment of the vessel.

In June of 2003, the vessel proceeded to Singapore for short-term layup and commencement of her scheduled drydock and repair period. The work on the vessel commenced in October of 2003, lasting until February of 2004. 783 tons of steel was renewed throughout the length and breadth of the vessel. In conjunction with the steel renewals the forepeak, afterpeak, and aft transverse ballast tanks were grit blasted and a new epoxy coating system applied. Those areas of the structure where renewals were made (thus disturbing the existing coating) were:

- Hydro-blasted.
- Cleaned with chloride removal chemicals.
- "Hand Tooled" in areas surrounding the blasted areas
- Coated with a three-coat epoxy system.

Using the above procedure, we have enjoyed success with coating repairs where the failure rates in the affected ballast tanks are in the five to ten percent range. We have shown this type of repair to dependably endure for a 5-year period. The cost of completing this repair is generally 1/10 the cost of total blast and re-coat. This type of repair is of particular importance on those vessels with a limited remaining service life, but that is still required to have their coating systems maintained in a "GOOD" condition for Class and vetting consideration.

The Alaskan Frontier, the first of four 185,000 MT DWT vessel's presently under construction at NASSCO in San Diego, is the future for ATC. Each vessel is constructed for the transportation of crude oil world wide, with an emphasis on the high visibility associated with the Trans Alaskan Pipeline Trade. The four vessels are owned by British Petroleum and represent a capital investment of $1 billion dollars.

The vessels are double-hulled crude carriers, constructed with an eye towards redundancy. Included are two independent engine rooms, two diesel-electric propulsion systems, two fixed pitch propellers, two steering gears, and two rudders.

The two propulsion plants, together with the essential auxiliary machinery and steering gears, are arranged in two fire tight, gas tight, and watertight machinery rooms. The spaces are arranged such that a catastrophic fire or flooding in any one space will not incapacitate the propulsion machinery, its auxiliary support equipment and associated steering systems in the other spaces.

Environmentally, the Alaskan Class Vessels will be the first vessels in the Trans-Alaskan Pipeline trade to employ a water-cooled Stern Tube Bearing. Historically, leakage of oil through the stern tube seal, though minor in scope, has been a major area of concern in spills to sea.

The cargo tanks are divided into six (6) tank blocks longitudinally. The cargo tanks are arranged three (3) abreast separated by oil tight longitudinal bulkheads running the length of the cargo block. The arrangement allows for a total of eighteen cargo tanks and two (2) slop tanks.

The vessel's equipment is designed for an expected service life of twenty-five years.

Structurally the vessels have been designed such that the builder must demonstrate the longitudinal structure will have a fatigue life of not less than fifty years operating in the Taps Trade environment. This has been demonstrated through the utilization of SafeHull Phase-B and spectral fatigue analysis.

With regard to the vessel's coating/corrosion protection systems:

- The ballast tanks of each vessel are designed for not less than 15 years of service life.
- The underwater area of the outer hull is protected by an anti-fouling corrosive paint system with a minimum of fifteen-year coating life
- The underwater area of the hull will also have a tin-free anti-fouling paint system suitable for a minimum life of three years in service.
- Zinc anodes are provided for tanks in contact with seawater and are suitable for five years of service life.
- All coated tank hull structures will have all sharp edges removed by edge grinding. Grinding will be accomplished to ensure a 2 mm edge radius. (The attention to detail in respect to this requirement has been phenomenal. Credit should be given to Nassco in their adherence to this requirement.)
- External to the hull all required frame markings required to allow the vessel to complete an underwater examination in lieu of drydocking will be provided.

The intent is for the vessels to be structurally sound and capable of a five-year drydock interval.

As a tank-ship operator with vessels operating under the authority of the Jones Act, our concerns are particularly unique. While we are expected to meet International Standards for vessel condition, many times our vessels are disqualified by age alone. Despite the fact that we take great pride over the level to which our vessels are maintained, the remainder of our single hull and double bottom vessels will be retired within the next two years. Our entire fleet will be comprised of double hull vessels.

We have shown how increased scrutiny by regulators about coating condition and the overall structural integrity of vessels demands the advancement of coating systems and their application. If coating systems are allowed to degrade, not only will inspection criteria become more stringent, but the vessels will quite possibly be considered a commercial risk and therefore, unfit for charter. If coating systems do not continue to advance in durability, cost of application, and level of protection, it will be difficult to stand the ever-increasing scrutiny while continuing to remain economically viable.

We have looked at the life cycle of the PRINCE WILLIAM SOUND, a vessel who started her career with uncoated tanks. We have seen the results of that flawed decision, and the many millions of dollars spent to return her to a condition that will make her commercial viable for the carriage of oil at sea.

Finally, we have looked at the future of our business with the construction of the Alaskan Class vessels. We expect the technology in place today and upcoming future developments will allow this vessel to fulfill its planned life cycle with reasonable economy. The staggering replacement cost of these vessels will necessitate technological advancement in coating system repairs and prolonged life cycles of entire coating systems.

Practical Experience

Adolfo Bastiani
Vice-president Offshore Operations
MODEC International LLC, Houston

Introduction:

This seminar is organized to discuss, at a high technical level, the causes, effects and remedial measures to combat corrosion in the offshore industry. I will leave the more technical aspects of this discussion to other distinguished speakers. My presentation here will outline our practical experience of one MODEC operated ship shaped FSO located in the southern Gulf of Mexico. That this body of water is also called the US Gulf should be of particular interest to many of the participants in this seminar, in the sense that it is a common body of water. Over the past couple of years, concern has been expressed that locating FSO/FPSO's in U.S. waters is not safe from pollution point of view. MODEC's experience with operating our FSO in GOM has been quite successful over the past six years without any incident of oil pollution and has an excellent HSE record.

The very concept of FPSO's is based on exploiting marginal oil fields and it is customary for all our clients to demand an FPSO that will operate in one location for 15 to 20 or even 25 years WITHOUT DRY-DOCKING. Whether it is a new build or a converted hull, this long life expectancy is a tall order indeed. Besides no dry-docking, the contract is always quite demanding re downtime. Either zero or minimal few hours every month, the downtime does not allow the contractor any freedom for remedying corrosion wastage during operations, particularly in inaccessible areas of underwater hull, moorings, sub-sea structures and even cargo/ballast tanks. The rationale of not stopping production is fully understood by the contractor as this has substantial and often unbearable economic impact.

Right from FEED study, the contractor must ensure optimum corrosion protection for the operational life. In addition, he must take into account thickness of steel plating, such that if there is failure of paint coatings, the wastage caused by direct attack of corrosive seawater, still retains the integrity of the hull over the entire life expectancy. As always, all such studies are done and must be implemented under strict budgetary control.

TA'KUNTAH – General Information and Capabilities

TA'KUNTAH was converted to an FSO in Singapore in 1997/98 from a ULCC hull, which was then twenty years old. A study of past trading pattern, extensive

thickness gauging before conversion and fatigue analysis over the designed life extension of fifteen years resulted in renewal of about 1200 tons of steel. Additional “fatigue brackets” were welded along the entire length of the hull. Hull coating was completed at the final dry-docking in March 1998 – just over six years ago. This FSO has now been on station 68 months. During conversion, ballast tanks were completely coated. Cargo tanks were partially coated underdeck and at the bottom, to a height of 3.0 and 1.0 meters, respectively. Cargo piping system was designed with extra thickness and was coated on the inside. Strict supervisory control was exercised over humidity, surface preparation and paint application.

Ta’Kuntah is a single hull vessel of 350,000 DWT with 29 cargo tanks (including slop tank) and total cargo capacity of 2.77 million bbls. In addition, forepeak, aft peak and two midship tanks are for water ballast. Fitted with a bow mounted turret, she is permanently moored in 80 meter depth of water with ten anchor legs connected to a chain table. This mooring system provides full weather vaning and is designed for a 100 year storm condition. Ta’Kuntah is located in the large Cantarell Oilfield of Pemex. Two flexible risers for incoming crude are connected with the sub-sea PLEM via a Mid-Water Arch in a lazy-S configuration. These risers are connected through a cargo swivel to the cargo lines on the FSO. Custody cargo meters are fitted on the loading and offloading lines. Ta’Kuntah is designed for offloading in both tandem and side-by-side modes. Three piggable ‘chiksans’ are provided on starboard side. For tandem offloading, 2 x 20 inch (reducing to 16 inch) floating cargo hoses are provided. Ta’Kuntah is capable of following simultaneous operations: loading, offloading to two tankers, crude oil washing of two tanks, purging, and venting the same two tanks, and tank entry/inspection.

In the 68 months of operations, 715 tankers have been loaded for an export quantity of 400 million barrels of crude. For many continuous periods of a month or more, frequency of tankers has been every 28 hours. Ta’Kuntah was conceived as a strategic storage and offloading facility but can now claim to be a fully capable offshore oil terminal.

In spite of such high commercial demands, MODEC is proud of the fact that there has been no downtime and no incident of oil pollution in over 2000 days of continuous operations. Ta’Kuntah is maintained in class and operates in compliance with all applicable Mexican and International Maritime Regulations including the ISM code.

<u>Brief details of Corrosion Protective Systems:</u>

<u>Paint systems:</u>

Ballast Tanks: Full coated. Sacrificial anodes installed.
One Stripe coat 500 µm

	Epoxy holding primer 50 μm Coal tar epoxy system – 2 coats x 150 μm/coat
Slop Tanks:	Fully coated. Sacrificial anodes installed. One Stripe Coat 500 μm. Epoxy holding primer 50 μm Coal tar epoxy – 2 coats x 150 μm each
Cargo Tanks:	Partial coated (top & bottom 3.0 and 1.0 meters respectively)
Hull topsides:	Four coat system (275 μm Total thickness) as follows: Zinc silicate – 75 μm Micaceous iron oxide epoxy – 2 coats x 125 μm /coat Polyurethane – 50 μm
Hull wind/water area:	Five coat system (490 μm Total thickness) as follows: Epoxy primer – 40 μm Glass flake epoxy – 2 coats x 150 μm/coat Micaceous iron oxide epoxy – 100 μm Polyurethane – 50 μm
Hull under water:	Six coat system (865 μm total thickness) as follows: Epoxy primer – 40 μm Glass flake epoxy – 2 coats x 150 μm/coat Coal tar epoxy – 75 μm Self polishing copolymer anti fouling system – 3 coats x 150 μm/coat
Deck area:	Epoxy coating system 2 coats x 250 μm/coat
Piping:	External: Coal tar epoxy – 2 coats x 150 μm/coat Internal: Glass flake epoxy – 2 coats x 200 μm/coat
Impressed current system for hull:	Wilson Walton Aquamatic III Lead/silver Anodes fitted on both sides of hull in forward/ amidships/stern areas. These anodes were fitted over specially coated areas with di-electric coating.
Marine Growth:	Cathelco anti-fouling and ferro-injection system for seachests and
Protection system:	SW pipes.

Corrosion Control During Operations:

In recognition of the fifteen years designed life expectancy, following controls are exercised during operations:

a. ICCP and Cathelco readings are monitored daily and monthly log is sent to technical department of supplier for their appraisal and recommendations if any are duly complied with.
b. At every periodic tank inspection, coating is touched up wherever it may be disturbed. Surface is prepared by hand tools. In this regard, particular attention is paid to the aftermost bay and area just below the suction bell mouth, which is subject to cavitation. During conversion, the bell mouth was raised by two inches to gain access for this maintenance.
c. At every periodic inspection inside the tanks, thickness gauging is carried out and readings compared with original readings from the conversion yard. By and large, coatings are found better than 99 percent intact and thickness readings do not show any deterioration.
d. Tank anodes are inspected for any wastage. Having been fitted in already coated areas, the wastage so far is noted to be negligible.
e. Acidic attack that can be caused by the presence of H_2S gas released by the Maya crude cargo on the upper parts of cargo tanks, is minimized through dilution with fresh inert gas and purging.
f. PV valves and self closing devices on the tank vent pipes for ballast tanks are maintained in good condition to prevent ingress of fresh air into tanks.
g. The 'in & out' lengths of anchor chains are measured for thickness at every five yearly interval to check on undue wastage. At last recording, this wastage was noted to be less than two percent on the diameter.
h. Maintenance of deck plating and fittings above deck are continuous maintenance items and are descaled and touched up or coated as necessary.
i. The exterior of the hull, where accessible, is touched up with paint as necessary.
j. The glass flakes coating in way of fenders provide extra protection against abrasion.
k. The inaccessible underwater areas of hull are inspected with the help of divers every 2.5 years. Obviously, no maintenance by way of recoating is possible. However, at such inspections, it has been noted that the extensive coating system applied at the conversion yard is by and large fully intact. Where superficially disturbed, it is noted that substrata of paint coating is quite intact still. At last underwater inspection carried out by divers and monitored on deck with video cameras, in March 2003 (i.e. five years after dry-docking), showed that there was hardly any sea growth –

barnacles etc. This indicates that anti-fouling coats are still effective. We have no delusions that this can continue for another 10 years. However, we feel confident that corrosion if/when it starts will not cause the integrity of hull to be unduly effected. It may be added that the rudder and propeller areas, which are isolated from the ICCP system, are extensively covered with barnacles. This is inconsequential for FSO/FPSO, as at the end of their life they will be towed away.

l. During such underwater inspection, particular attention is paid to the seachests and their external gratings. If necessary, gratings are removed to the deck and recoated. Anodes inside the tanks are noted to be quite active and when needed, they can be replaced.

Let me end my presentation by stating that the corrosion protection provided at the time of conversion six years ago and subsequent inspections and corrective measures and controls exercised during operations of this FSO located in its particular area in GOM, give us the confidence that Ta'Kuntah will outlive its life expectancy of fifteen years.

Section 3

Theme Papers

Health & Safety Concerns:
Coating Application & Removal

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Introduction:

The intent of the paper is to provide a very brief summary of potential safety and health concerns/hazards associated with the coatings industry for inclusion in this publication. This paper is far from a detailed, thorough assessment of any and all hazards associated with the practices of this industry.

Extremely simplified, the application of a coating involves the removal of any previous coatings/paints, followed by surface preparation, and subsequently, the application of new coating.

Removal of old coatings and surface preparation is usually accomplished via water blasting, steam blasting or abrasive blasting. This process often creates a large debris cloud of both blasting media and removed product.

The application of a coating involves either spraying or brushing the material onto the prepared surface. This frequently results in an atmosphere with high concentrations of aerosolized coating material.

Most coatings, paints, and protective agents are comprised of a long list of materials, many of which have properties that make them potentially harmful to human health. Ingredients will likely include some type of solvent (aromatic and aliphatic hydrocarbons) mixed with pigments and additives. The additives may include organo-mercury compounds, copper oxide, arsenic, organo-tin compounds, cadmium, chromium, lead, zinc chloride, and others.

The process of surface preparation and application of the coating, coupled with the potentially hazardous materials used in the coating, create occupational health risks that could cause both acute and chronic illnesses to workers.

General Safety Concepts:

The most effective way to assess the potential hazards associated with utilizing a product is by consulting its Material Safety Data Sheet (MSDS). The application of coatings is no exception. It is imperative that workers that will be handling the

coatings acquire the appropriate MSDSs and gather information on the hazards, handling procedures, PPE requirements, etc.

Utilizing controls is essential. The control hierarchy dictates that engineering controls should be considered first, followed by administrative controls, and finally the use of Personal Protective Equipment (PPE).

Engineering controls are those that can eliminate the hazard through technology. Installing blockades, shields, local ventilation, or isolation booths are engineering controls that isolate the hazard from the worker or the worker from the hazard.

Administrating controls are policies or procedures aimed at limiting or minimizing workers exposure to hazards. Work rest cycles, warning signs, and worker training are all admin controls that can reduce the likelihood of injury or illness due to hazard exposure.

The last control is the use of PPE. Often times unavoidable due to procedures and practices, the use of respirators, gloves, coveralls, etc will minimize workers exposure to certain chemicals/hazards.

The control hierarchy should always be addressed prior to commencing a job to determine the best way to protect the workers and the surrounding area.

Fire and Explosion Hazards:

The vast majority of paints and coatings contain some type of solvent. These solvents are commonly the carriers of any pigments and additives used in the coating. Examples of commonly used solvents include mineral spirits, benzene, toluene, acetone, methyl ethyl ketone (MEK), and others. Though all have differing physical and chemical characteristics, one property common among most solvents is that they are extremely flammable.

Whether applied via spraying, brushing or other technique, all are likely to create a potentially explosive atmosphere. This atmosphere combined with a source of ignition may result in a catastrophic explosion.

Sources of ignition could include hot-work (welding, cutting, grinding), non-intrinsically safe equipment/tools, human error, etc.

Often times sources of homogenous to the job site and cannot be eliminated. As such, the best preventive measure is to aggressively ventilate the space. Exhaust ventilation must be utilized to ensure flammable solvent vapor concentrations are <10 percent LEL.

Respiratory Hazards:

Solvents, pigments and additives may all be respiratory hazards.

Application or removal of coatings in confined or enclosed spaces could result in an oxygen deficient atmosphere or an atmosphere with high levels of toxic material. Potential health effects due to exposure to some products may include irritation, sensitization, organ damage, cancer, neurological damage, asphyxiation, or death. Therefore, respiratory protection in the form of air-purifying respirators (APR), supplied air respirators, or self-contained breathing apparatus is a must in most situations. In confined spaces and enclosed spaces without ventilation, airline respirators are required. In well-ventilated areas, air-purifying respirators with appropriate cartridges are acceptable.

The best preventive measure is again ventilation and real-time air monitoring to ensure toxics remain below OSHA's Permissible Exposure Level (PEL) and ACGIH's Threshold Limit Value (TLV).

Contact with Coatings or Solvents:

Components of many coatings can cause irritation, sensitization, allergic reactions, chemical burns, organ damage, etc. if they come into contact with skin or eyes. Proper PPE should always be utilized including utilizing full body coverall, face and eye protection, gloves, boots etc. Eyewash stations and emergency showers must be available for worker use.

Limited Access/Egress and Confined Space Entry:

Painting and coating operations that take place inside tanks and other voids commonly result in blocked access openings and limited egress. It is imperative that these entry and exit points remain clear to avoid the hindrance of escape in the event of an emergency.

Proper confined space entry procedures must be followed when entering space to apply or remove coatings. Certified Marine Chemists and shipyard competent persons must be used to test the spaces for oxygen content, flammable atmosphere, and the presence of toxics.

Work Environment Temperature and Related Hazards:

If not properly accounted for, both heat and cold stress can create dangerous work environments.

The most important action required is the monitoring of the environment. Utilizing a Wet Bulb Globe Temperature (WBGT) monitor, a health tech can determine whether temperature related stress is an issue. Administrative controls should also be considered which include work / rest cycles, frequent breaks, hydration, and awareness training.

Slip, Trip, and Fall Hazards:

Injuries due to simple trips and falls are by far the most common injuries occurring in the occupational environment. The field of coatings and paint application is not an exception to this trend. It is imperative that all workers are familiar with their environment and are aware of the uneven work surfaces, deck openings, platforms, overhead hazards, etc that are potential sources of injury.

High Pressure Hazards:

High-pressure pneumatics is routinely called upon for the application/removal of coatings and paints. Pressurized steam, water and abrasives are commonly used to remove old product and otherwise prep surfaces for new coatings. This exposes workers to noise, thermal, injection, physical (eye & skin), and inhalation hazards.

Electrical Hazards:

The coatings industry obviously relies heavily on electrical power to run equipment, tools, lighting, ventilation, etc. With this reliance, come the associated hazards. These hazards may include shocks, arc burns, blasts and sparks resulting in electrocution, vapor ignition, and secondary injuries such as falling after a shock. Vigilance must be applied to the inspection of equipment, cords, tools and potential static build-up.

Detailed Health and Safety Information:

As stated above, this information is a very broad, simplified look at potential health and safety issues that may be associated with the coatings industry. The following references are valuable sources for more detailed information:

http://www.osha.gov/SLTC/etools/shipyard/shiprepair/painting/index_paint.html

http://www.cdc.gov/niosh/homepage.html

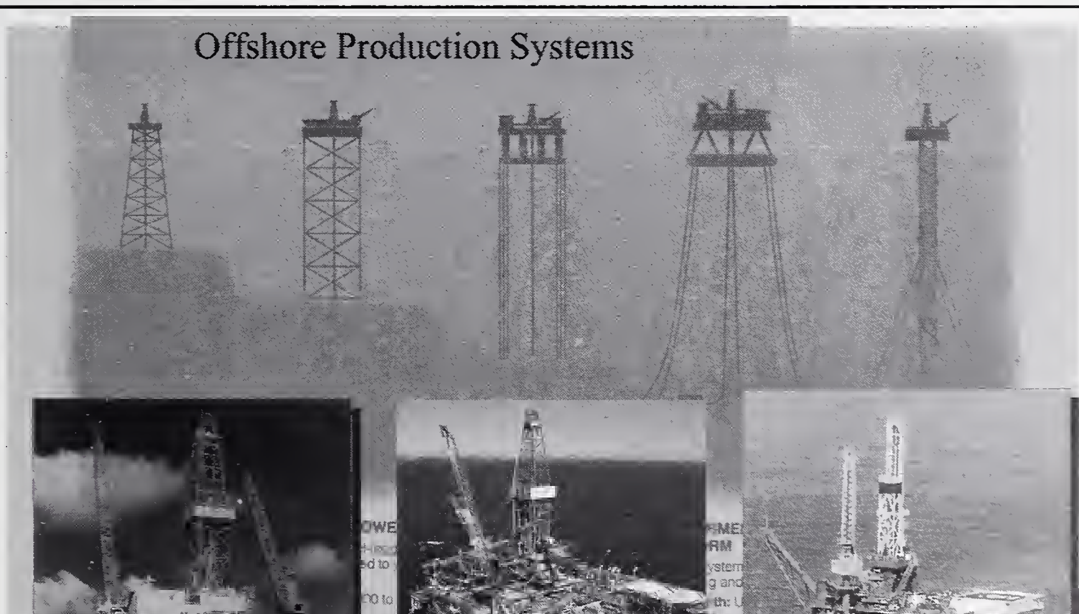
http://www.epa.gov

Coatings for Corrosion Protection

April 14 2004

Tankers and FPSO Corrosion

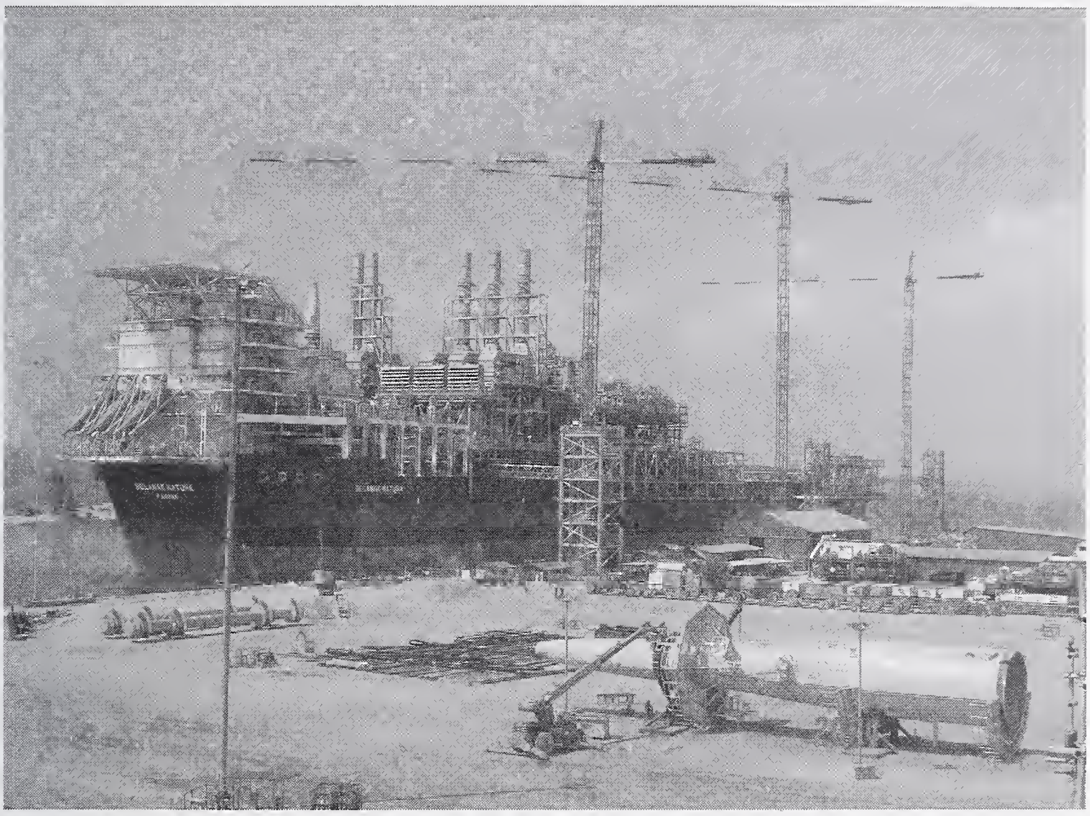
Ian Rowell
International Paint



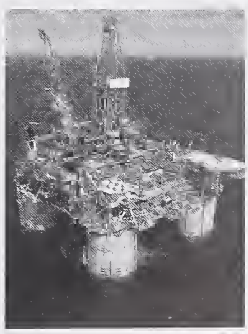
Floating Production Units

General Observations

- Floating Production Units have been in operation for over 15 years. Now nearly 200 in operation
- Units are increasingly operating in deeper water in locations that are more inaccessible
- The Costs of Offshore Coating Repair or Maintenance is significantly higher than New Construction – ***x15***
- Units are operating in Hot Climates with very corrosive conditions
- The types of structure used and how they are built is changing
- Projects are increasingly Global

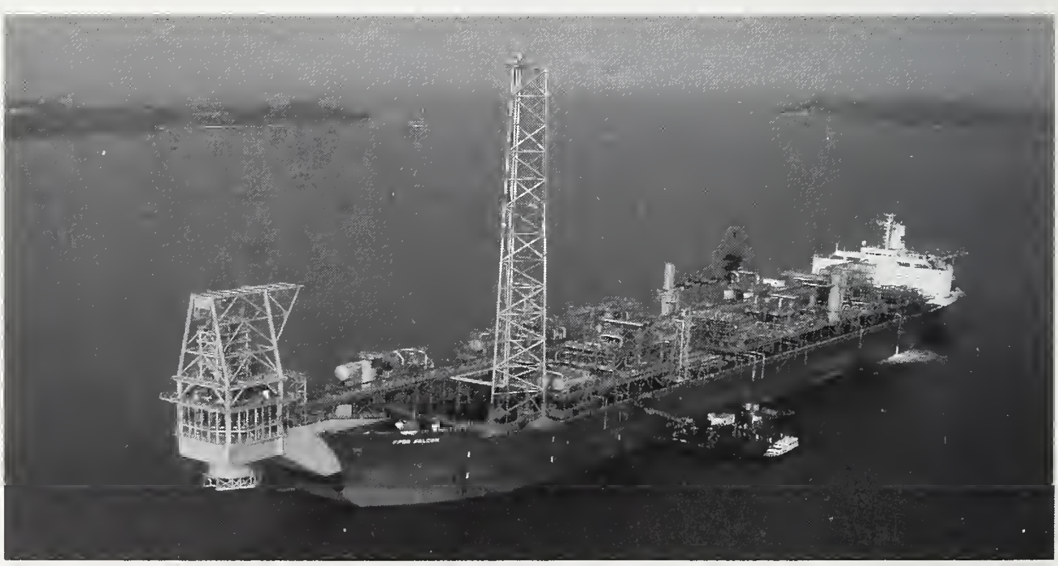


FPSOs - Getting it Right 1st Time



Getting the balance right

•Tanker coating requirements are different than those for offshore structures
•Established building practices
• Tankers dry dock at MAXIMUM 5 year intervals
• No product testing protocols



Why is an FPSO Hull different?

• Design life is commonly +25 years – without drydocking
• Ballast tanks can cycle as much in a month as a tanker in a year
• Commonly hot oil at +160F into the tanks

FPSOs - Getting it Right 1st Time

Needs are Different

PRODUCTIVITY **PERFORMANCE**

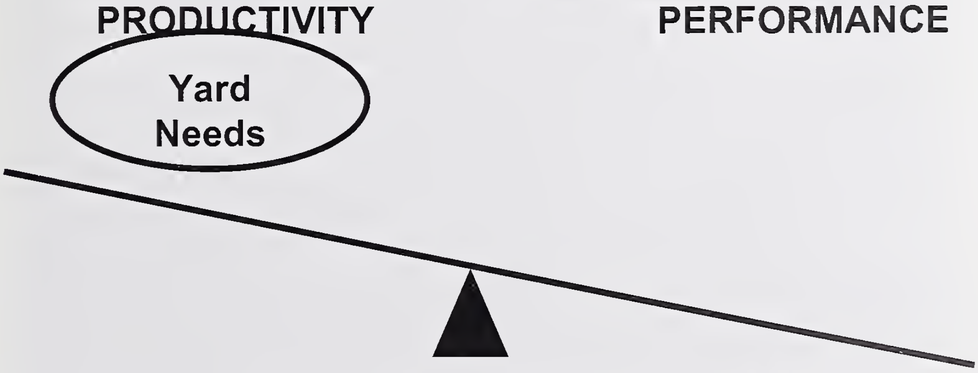
Getting the balance right

Products meeting Owners <u>and</u> Yard needs

FPSOs - Getting it Right 1st Time

Needs are Different

PRODUCTIVITY **PERFORMANCE**



Getting the balance right

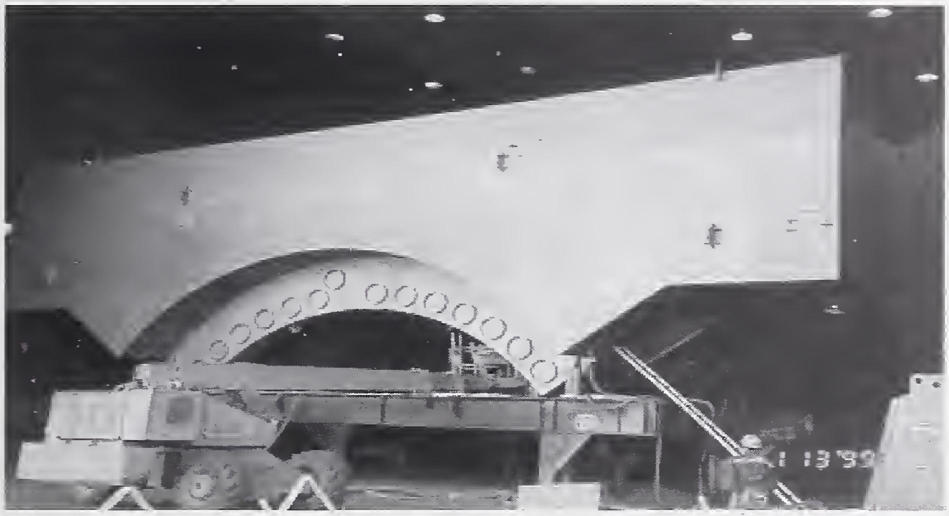
Products meeting Owners <u>and</u> Yard needs

New Construction is inevitably in Asia

FPSOs - Getting it Right 1st Time

Block Assembly in Fabrication Hall

FPSOs - Getting it Right 1st Time

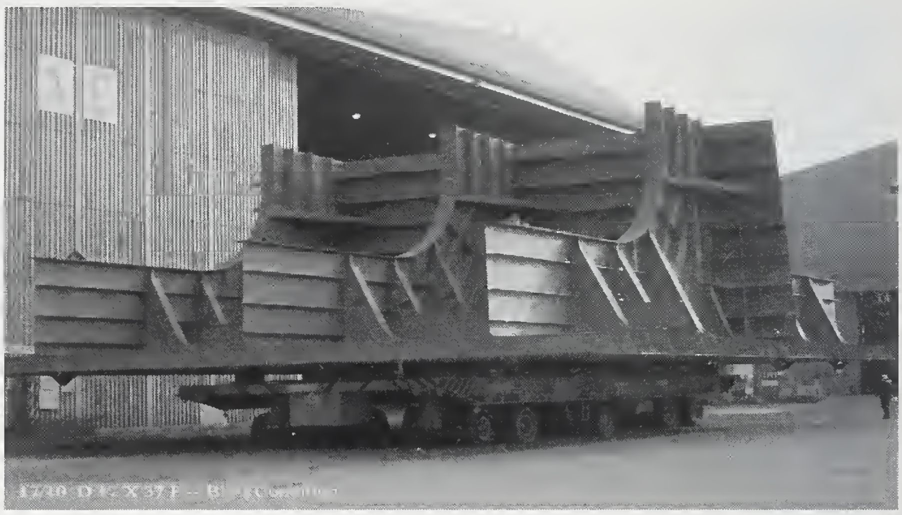


Block after removal of PCP

FPSOs - Getting it Right 1st Time

Coated Block in Painting Hall

FPSOs - Getting it Right 1st Time

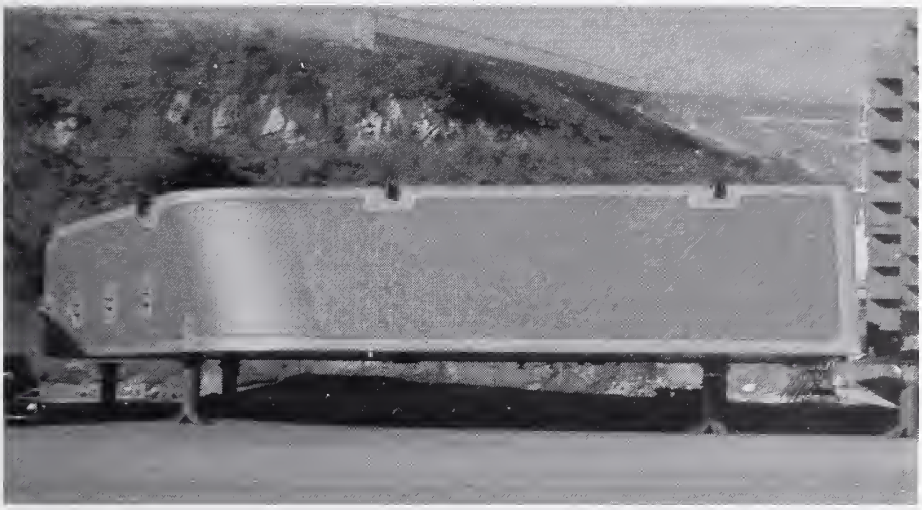


Block being moved around yard

FPSOs - Getting it Right 1st Time

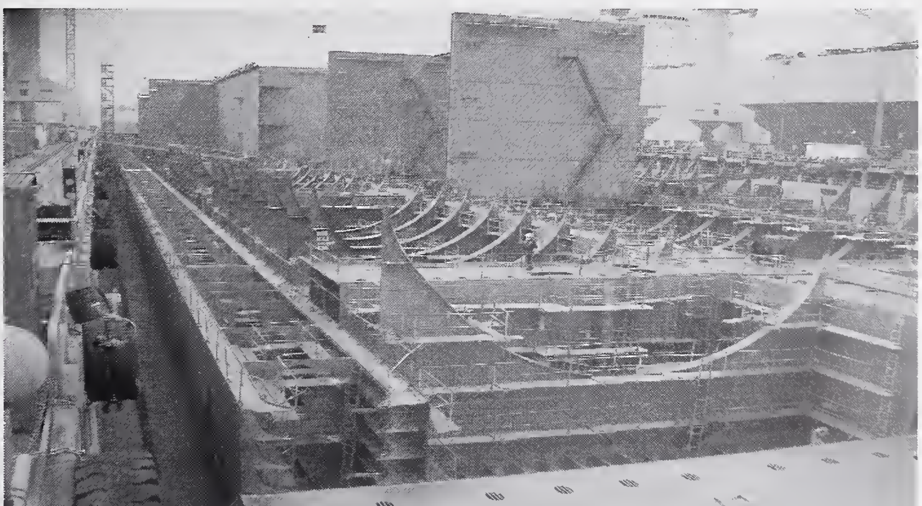
Coated Block being moved around yard

FPSOs - Getting it Right 1st Time



Block in storage in yard

FPSOs - Getting it Right 1st Time

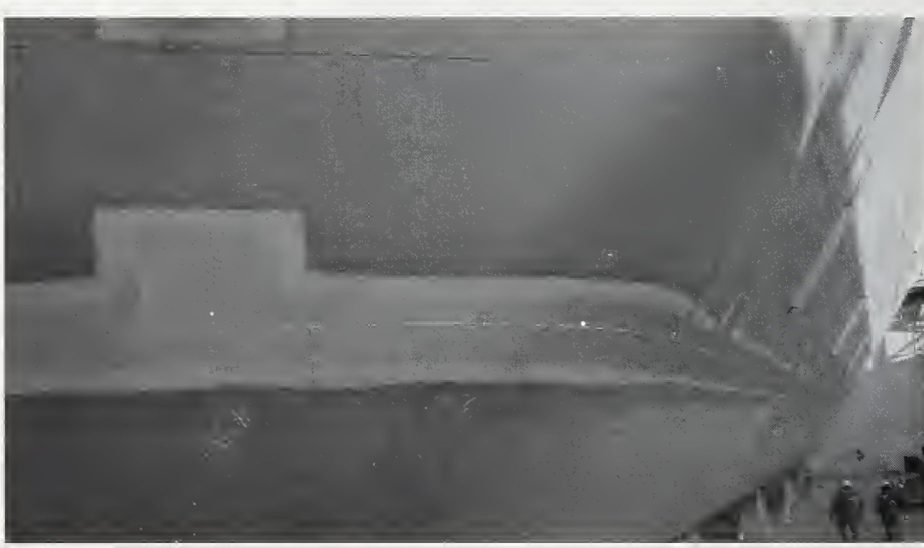


Block assembly

FPSOs - Getting it Right 1st Time

Block Assembly

FPSOs - Getting it Right 1st Time



Prepared Block Joint – **NO ABRASIVE BLASTING**

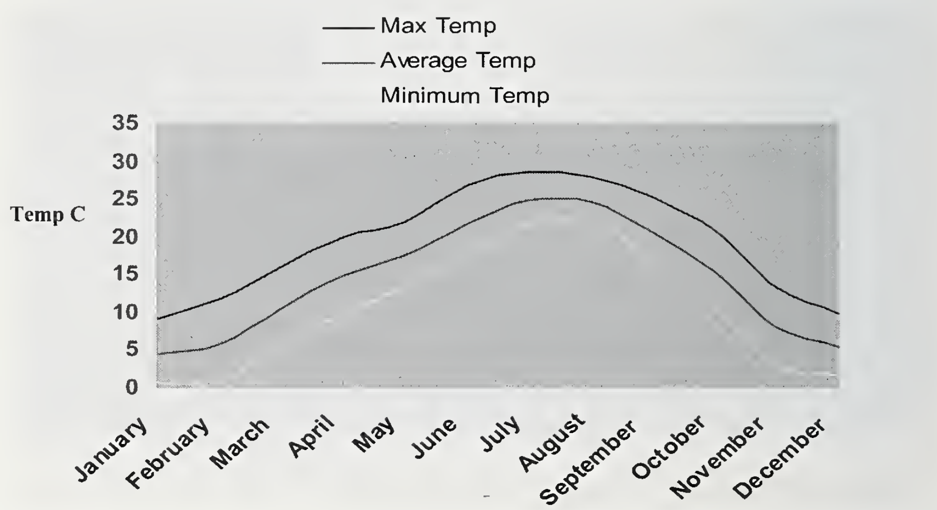
FPSOs - Getting it Right 1st Time

Block Joint Coating

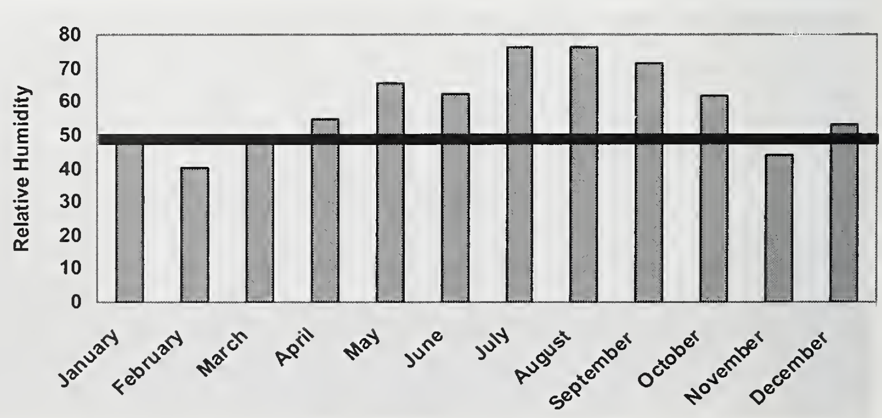
FPSOs - Getting it Right 1st Time

Partially coated block joints

Temperatures – Ulsan, Korea



Relative Humidity – Ulsan, Korea



DO NOT USE INORGANIC ZINC

New Construction – Cold Climate in Winter
M&R - Hot Climate

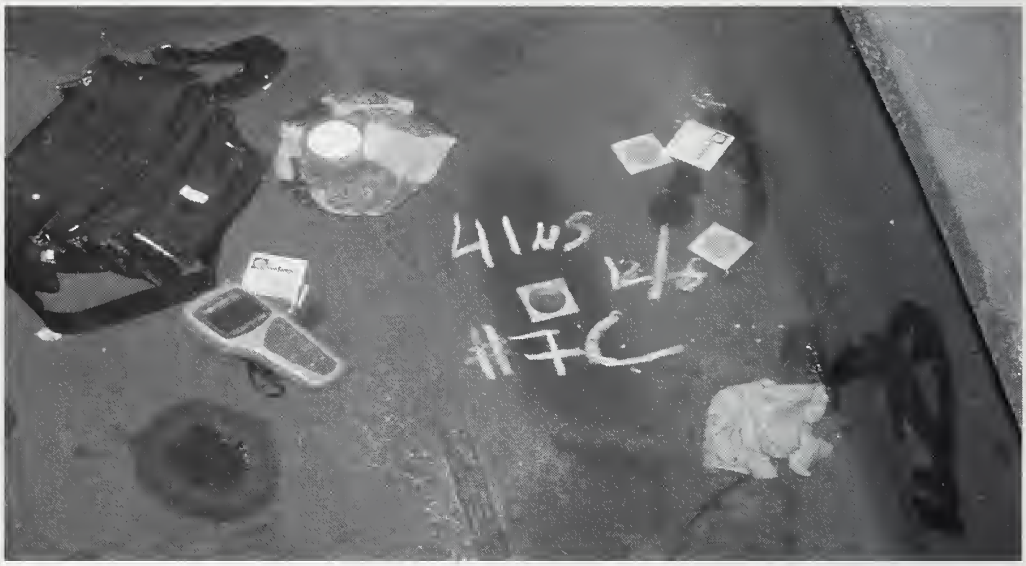
• **Conversion of approximately 20 year old tankers is common**

Major steel replacement and modification is required

Existing coatings are fully removed – need a new 20 year system

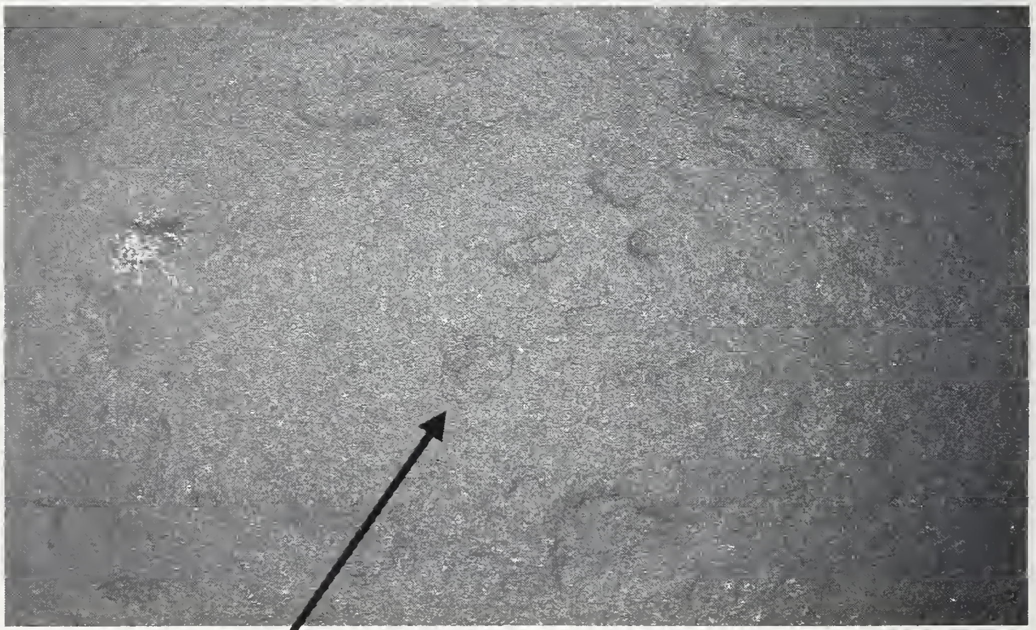
Automated blasting

20 year old cargo and ballast tanks inevitable are heavily corroded

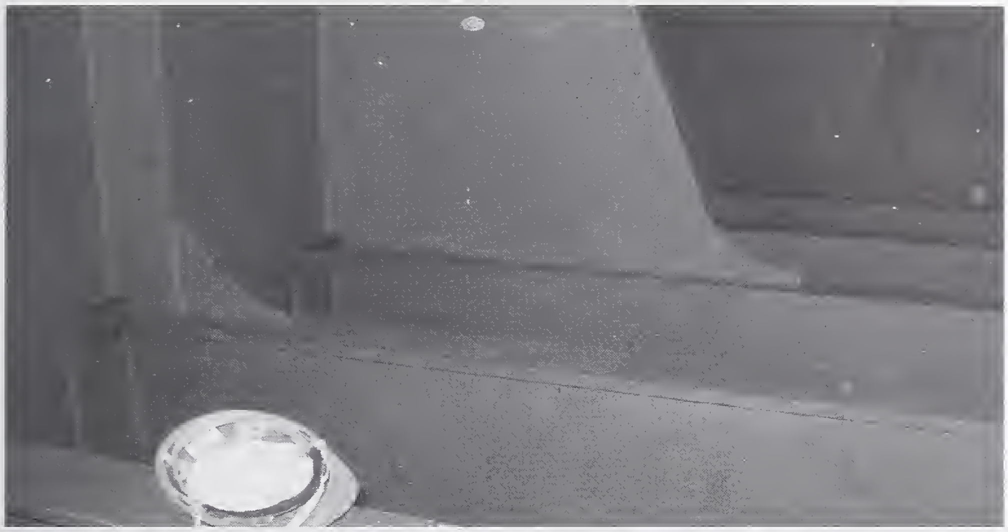


Steel is heavily contaminated with chlorides

Key question how to reduce chlorides and to what level?

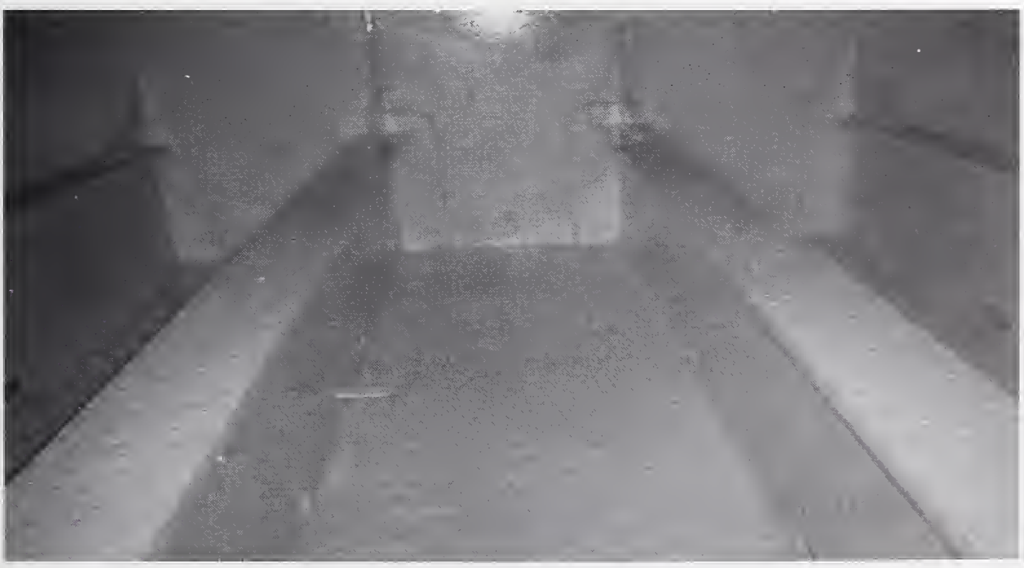


Heavy pitting

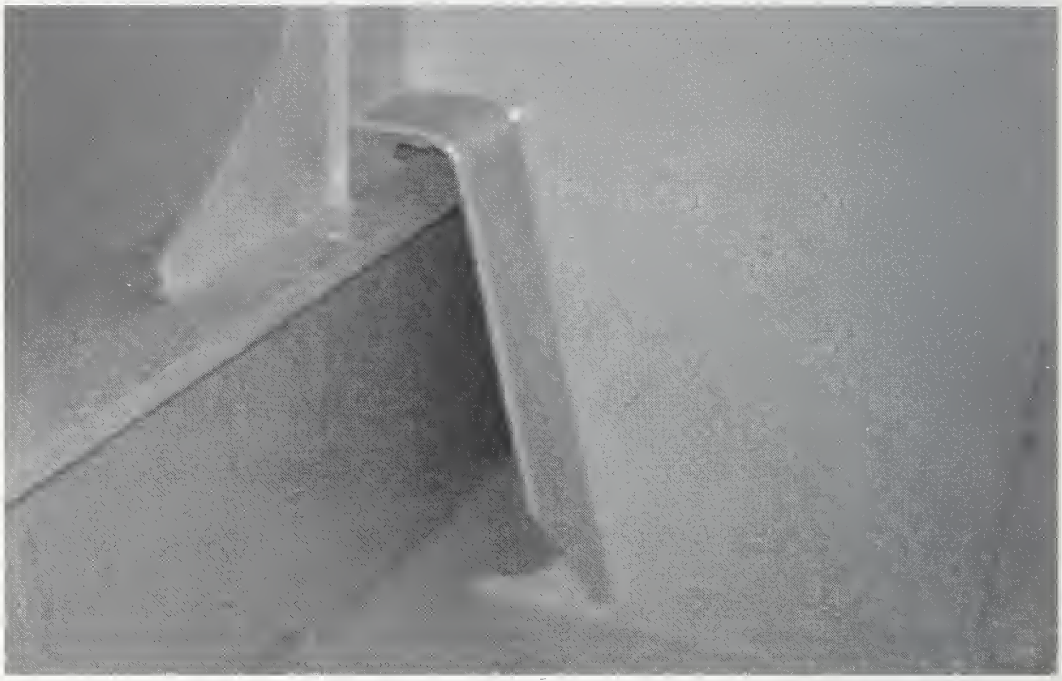


Areas are complex

Air movement and humidity control is difficult



Preferred coating is SOLVENT FREE
• No concerns with solvent entrapment
• Penetrates deep pitting
• Reduction is explosion hazard from solvent vapors



Yard Product – New Construction

Multi Purpose
- Ballast,Cargo & Slop Tanks
- Underwater Hull
- Over Zinc Primer as build coat
- Decks

Fast Recoat, Rapid Handling

Long Maximum Recoat

Low Temperature Cure

Not dependant on humidity

Yard Product – Conversion

Multi Purpose
- Ballast,Cargo & Slop Tanks
- Underwater Hull
- Over Zinc Primer as build coat
- Decks

Fast Recoat, Rapid Handling

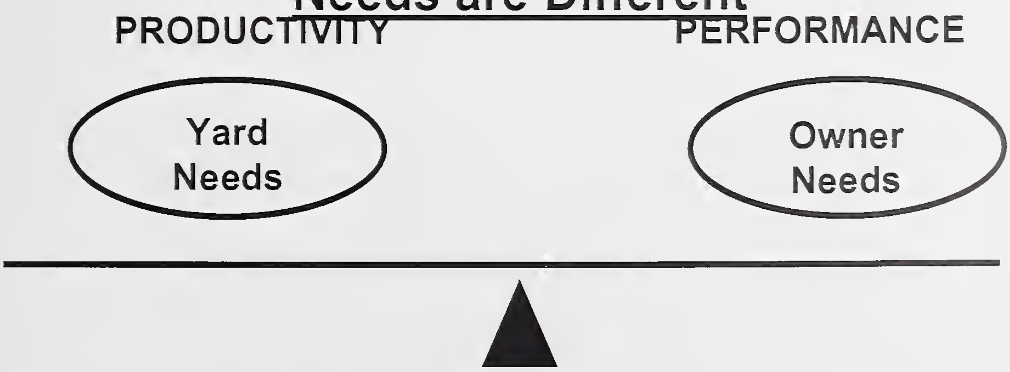
Long Maximum Recoat

Tolerates high temperatures

Tolerates high humidity's

FPSOs - Getting it Right 1st Time

Needs are Different



Getting the balance right

Products meeting Owners and Yard needs

Standards Developed – Current Status (All in draft format)

- NACE TG260
  - "Offshore Platform <u>Atmospheric</u> and <u>Splashzone Maintenance</u> Coatings"
- NACE TG263
  - "Offshore Platform <u>Ballast Water</u> Coatings"
  - New Construction and Maintenance
- NACE TG264
  - "Offshore Platform <u>Exterior Submerged</u> Coatings"

- <u>Effective & Economical!</u>
- Wider approach adopted in simulation of failure modes
- Resulting in "multiple tests"
  - Cyclic corrosion testing, residual salt resistance, immersion, edge retention, thermal cycling, flexibility, impact, abrasion, dimensional stability
  - <u>Specialist tests</u> developed where necessary
    - ISO / ASTM used where applicable
  - Each NACE standard uses applicable tests ONLY
  - <u>Recommended</u> pass criteria

NACE TG260 - "Offshore Platform Atmospheric and Splashzone Maintenance Coatings"

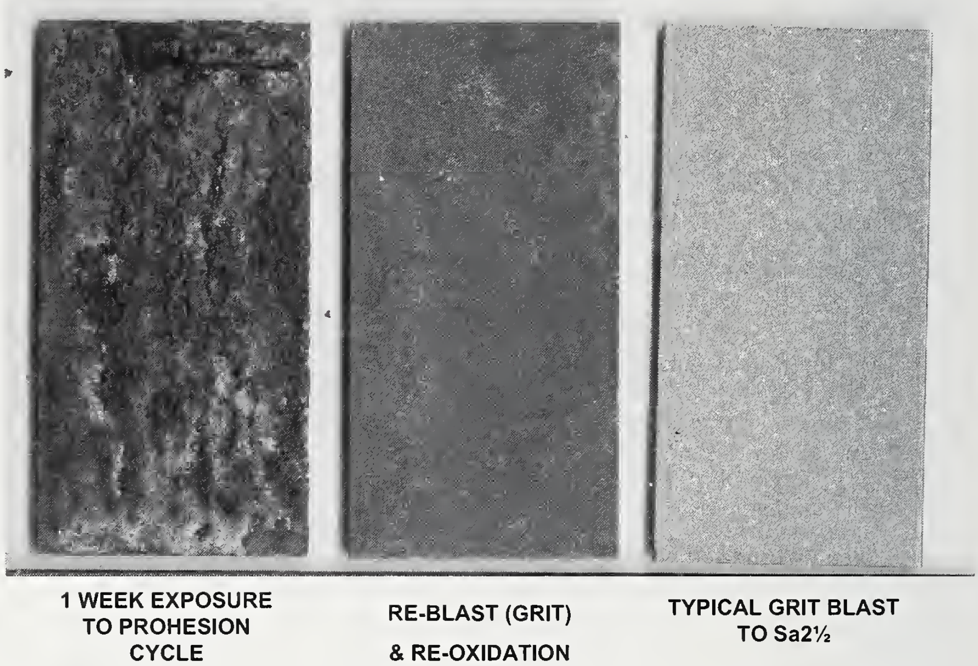
Test Type	Standard	Duration	Recommended Pass Criteria
Cyclic Corrosion (Rust Creepage)	Modified ASTM D5894 Synthetic Seawater	12 weeks	<3mm creep non zinc <1mm creep zinc
Cyclic Corrosion (Residual Salt Rust Creepage)	Modified ASTM D5894 Synthetic Seawater	12 weeks	<3mm creep non zinc <1mm creep zinc
Edge Retention @ 90°	N/A	N/A	>0.5
Thermal Cycling	+60°C to -30°C 2 hour cycle	252 Cycles	No Cracks
Flexibility (60°C ageing 1 week)	Modified ISO1519 (Fixed Mandrels)	N/A	>1% Flexure Strain
Impact Resistance	ASTM G14	N/A	>3.4 joules
Abrasion Resistance	ASTM D4060 (CS17 wheels)	N/A	<50μm thickness loss per 1000 cycles
Water Immersion @ 40°C (Splashzone Only)	Modified ISO 2812-2 Synthetic Seawater	12 weeks	No pinholes / rust >3.4MPa / <1mm disbondment

NACE TG263 - "Offshore Platform Ballast Water Coatings"

Test Type	Standard	Duration	Recommended Pass Criteria
**Cathodic Protection	Modified ASTM G8 Synthetic Seawater	12 weeks	<1mm disbondment
**Water Immersion @ 40°C (Splashzone Only)	Modified ISO 2812-2 Synthetic Seawater	12 weeks	No pinholes / rust >3.4MPa / <1mm disbondment
Dimensional Stability (Free films)	Synthetic Seawater @ 40°C	12 weeks	Within +/- 0.75% change
Ageing Stability (Flexibility)	Modified ISO1519 (Fixed Mandrels) Control & Aged	Aged = 12 weeks immersion	>50% flexure strain ratio of aged / control
Edge Retention @ 90°	N/A	N/A	>0.5
Thick Film Cracking	3 x 500μm Synthetic Seawater @ 40°C	12 weeks	No Cracks
**Hot / Wet Cycling (FPSO's)	3hr wet @ 23°C 3hr dry @ 60°C	12 weeks	<3mm creep No pinholes / blistering

**** Carried out over "Damp" and Chloride contaminated steel (10μg/cm²) for maintenance**

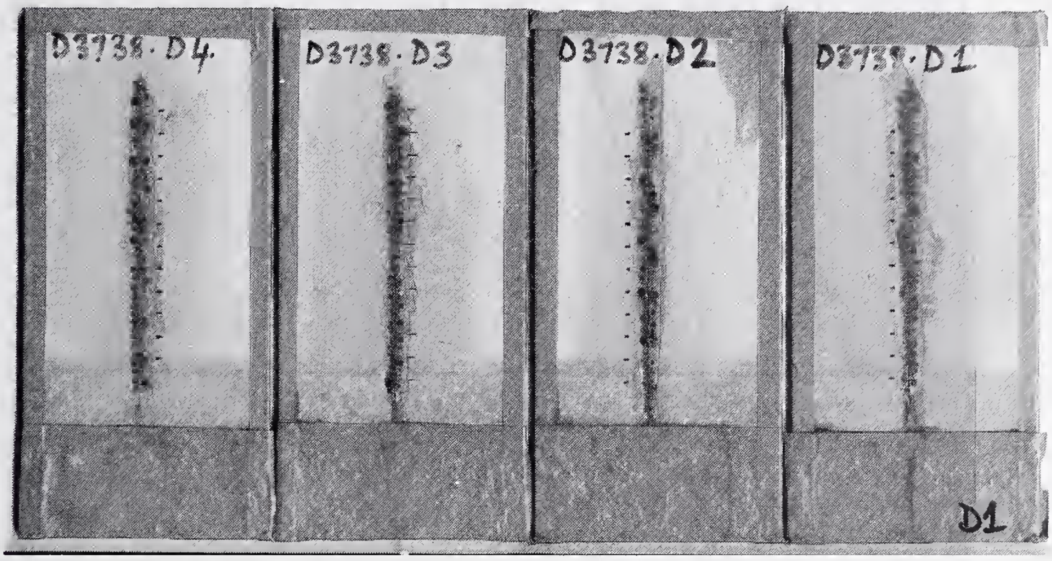
NACE TG260 – RESIDUAL SALT RUST



Cyclic Corrosion Test

- 168 hours Prohesion Salt Fog (ASTM G85)
  - 1 hour spray / 1 hour dry out
  - Artificial sea water electrolyte (ASTM D1141)
- 168 hours UV / Condensation (ASTM G53), 4 hours UV at 60ºC, 4 hours condensation at 50ºC
- All panels scribed with 9 cm x 1 mm vertical scribe
- One cycle = 2 weeks (336 hours)
- Test duration = 12 weeks (2016 hours)

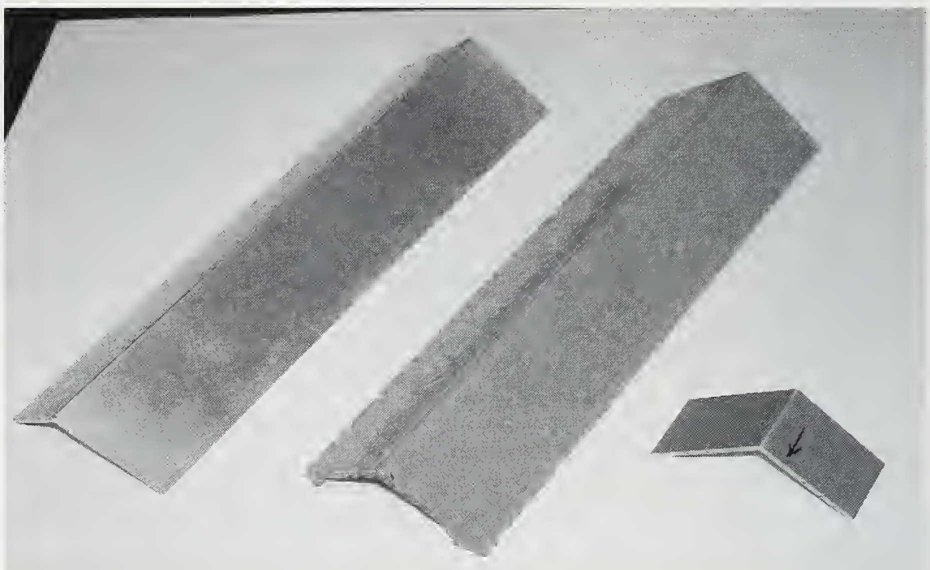
Cyclic Corrosion Test



Edge Retention

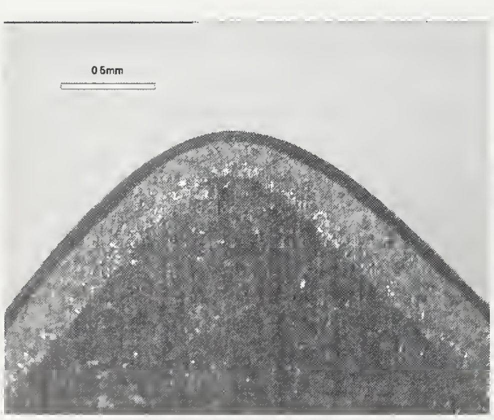
- Ability to retain film thickness on sharp corners
  - Related to rheological properties and spray technique
  - Test should be carried out using that which is used in the field
- Full coating application onto sharp 90° aluminium bar
  - Radius of curvature 0.7 mm or less
- Samples cut from bar
  - Smooth flat surface required
- Measure peak / side ratio using suitable microscope / optical hardware.

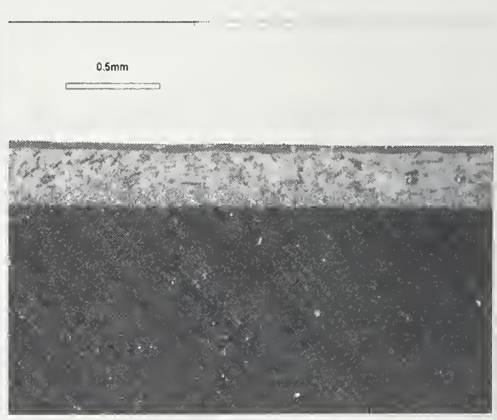
Edge Retention



Edge Retention

- Edge "retentive" Coatings (90° Corner)





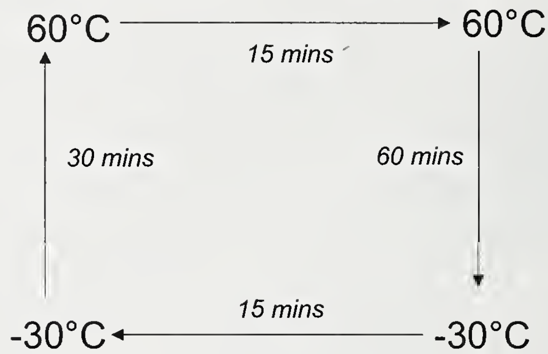
Thermal Cycling

- Offshore steel temperatures can vary significantly
  - Low temperatures – coating contraction
  - High temperatures – coating expansion
  - Causes "thermal fatigue"
  - Cracking results

Thermal Cycling

- Dry thermal cycling test
  - -30ºC to + 60ºC
  - 2 hour cycle/252 cycles (3 weeks)
  - "C-Channel" test piece (3 x 2 inch)
  - Standard film thickness tested
    - May not see too much failure at standard draft
  - Thermal cycling chamber
    - Programmable

Thermal Cycling



Total No. of cycles = 252 (3 weeks)

Draft NACE TG260 : Test Piece

Cyclic Corrosion Test

- Draft ISO 20340
  - 72 hours UV/Condensation (ASTM G53), 4 hours V at 60ºC, 4 hours condensation at 50ºC
  - 72 hours Neutral Salt Fog (ISO 7253)
    - 5% Sodium Chloride electrolyte
  - 24 hours freeze at –20ºC (or optional +23°C)
- One cycle = 1 week (168 hours)
- Test duration = 25 weeks (4200 hours)

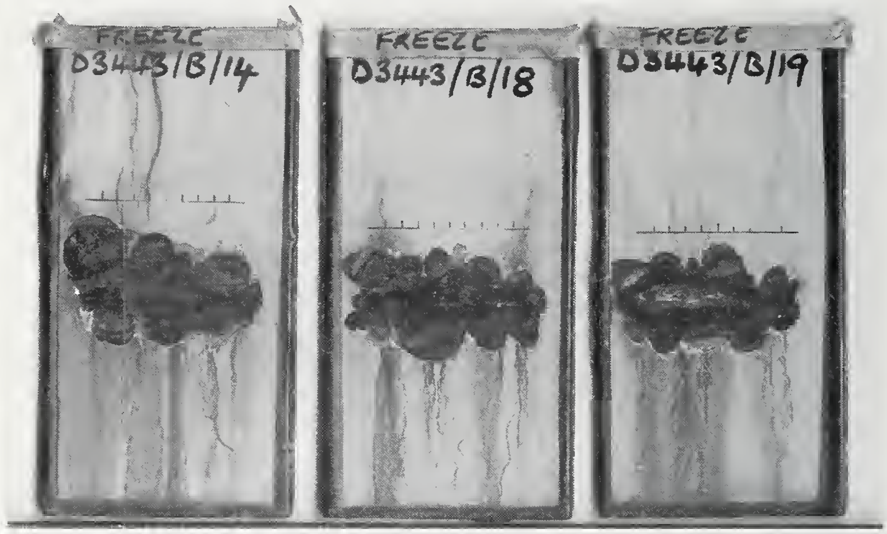
*** Consider freeze as being the more appropriate choice - stress**

ISO 20340 (4,200hrs) without Freeze

Photo no. 1. Panels after Cyclic salt spray / UVA test

7.4 mm creep 7.2 mm creep 7.4 mm creep

ISO 20340 (4,200hrs) with Freeze



14 mm creep 13 mm creep 12 mm creep

ISO 20340 Testing after 10 weeks
Power tool cleaned steel with profile

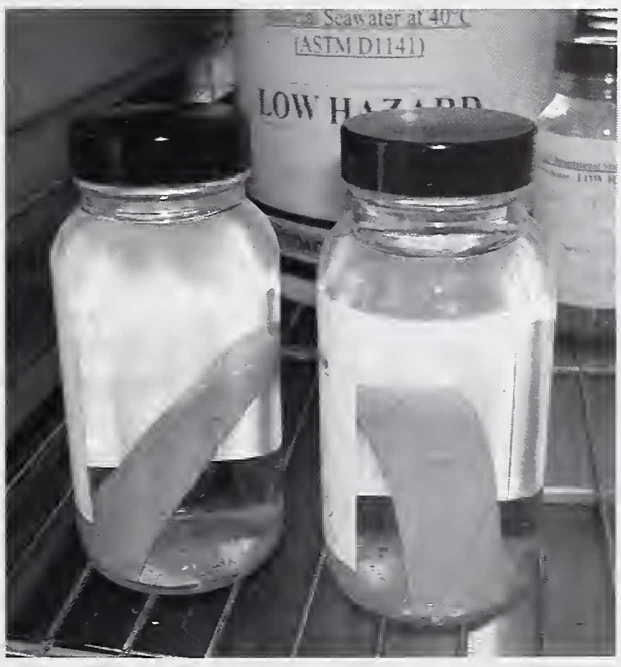
Ambient Dry 23°C With Freeze –30°C

Dimensional Stability

- Water moves in and out of coatings
- Absorbed water can cause "swelling" - Blistering
- Absorbed water can leave the coating taking with it water soluble additives
  - "Migration" of small species such as solvents / plasticisers
  - Can cause "shrinkage" / "Cracking"

- Testing of free films
- Weight and dimension measurements before and after seawater immersion for 12 weeks @ 40°C

Dimensional Stability

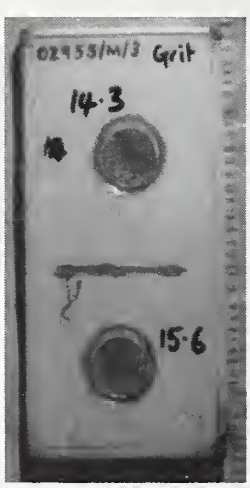


Cathodic Disbondment Test (ISO 15711)

- Defines two methods
  - Method A Impressed Current (-1.050 volts)
  - *Method B Sacrificial Zinc Anode (-1.050 volts)
- Electrolyte
  - Artificial seawater <u>or</u> natural seawater
  - Ambient temperature (23°C)
  - Testing required to 60°C
- Test Duration = 6 months

*Note : Method B is identical to SMT 97

Global Assurance of Product Quality



- Paint systems are tested to develop a performance profile
- Life expectancy is derived from performance during the testing program
- Paint formulations are easy to change

How can you get assurance of product performance ?????

ISO 20340 – Paint Identification

- Fingerprinting
  - Ensure consistency in the supply of qualified coatings
  - Paint supplied = Qualified Coating
  - Range of tests
    - Binder content/pigment content/functional groups
    - IR Spectra (ASTM D2372 & D2621)
    - Mass Solids (ISO 3251)
    - Density (ISO 2811)
    - Ash Content (ISO 14680-2)
  - Routine Batch Testing
    - Mass Solids/Density

Product Fingerprinting

Process to allow owners to control the quality of paint

- Testing Protocol established
- A unique Fingerprint produced for each coating
- Manufacturer establishes procedures to control
  - Raw Materials
  - Manufacturing Quality
- Manufacturer produces Certificates of Conformity for each batch
- Owner can sample paint and see if fingerprint is valid
- Manufacturer has to inform owner when a formulation change is being made

Inspection and Repair of Coatings

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Abstract

From the "birth" in the laboratory to manufacture, application and service use, inspection and repair protocols must be invoked to ensure optimum coating system performance. This theme paper reviews current practices and suggests broad areas of research efforts to improve the art. Because of the diverse nature of coating chemistries in use today, the focus will be directed to issues that are common to most of the available technologies. Because of the economic considerations associated with the repair process, a review of the major issues to address in the maintenance decision-making process is provided.

Introduction

The ultimate performance of coatings used for corrosion protection can be traced to the successful implementation of the following processes:

1. Formulation
2. Performance testing of new formulations
3. Manufacture
4. Transport and Storage
5. Initial system installation and inspection
6. In service inspection and repair

Given the large scope inherent in the processes described above, this theme paper assumes that coating materials have been properly formulated, screened for performance in the intended corrosive environment, and properly manufactured and delivered to the project site. Additionally, it is assumed that the correct materials and procedures have been selected for the intended service in the form technical and administrative specifications prepared by an engineering agency.

Given the assumptions mentioned above, inspection and repair of coating systems will be reviewed and opportunities for R&D initiatives to improve these processes will be identified. It should be understood that the term "inspection"

actually refers to two distinct processes that have different foci and prerequisite skills:

- In-process Inspection: The in-process inspector is responsible for ensuring that the coating system is installed in accordance with Project specifications. The in-process inspector conducts various tests on equipment, prepared surfaces and the applied coating film that establishes conformance to industry standards (typically consensus standards). Installation contractor's personnel, owner's personnel, "third-party" organizations, or a combination may perform the in-process inspection process. Part of the installation process may involve repairs to the system damaged by other trades or during the course of destructive testing.
- In-service Inspection: The in-service inspector is responsible for identifying the extent and degree of system deterioration (in relation to the system's ability to perform its intended function), identify "premature" failures and evaluate the system for three repair options. The three repair options are:
    - Touch-up: Addressing isolated failures of the installed system by the application of a repair system (that may or may not be the same as the installed system).
    - Refresh: Involves the combination of touch-up, followed by the application of a new topcoat. The existing system must be evaluated for its ability to receive the new topcoat.
    - Restore: Involves the complete removal of the existing system and the installation of a new system (not necessarily the same as the existing system).

The in-service inspection process carries with it a strong economic element. Repairs to existing coatings are typically more complicated and expensive than original installation. This is particularly true in terms of operating facilities, as the repair process may significantly impact the revenue stream generated by these facilities. Also, existing accounting system procedures penalize owners in terms of treating maintenance expenditures.

In-Process Inspection

The in-process inspector is often assigned a variety of responsibilities in a coating project. These duties may range from strictly addressing inspection issues to assumption of traditionally project manager duties. Bearing in mind that many maintenance projects encompass more than the application of coatings, the in-process inspector may have to assume responsibility or work closely with other personnel (welding inspectors, QA/QC, engineers, operational personnel, etc.). Generally, the in-process inspector is responsible for:

- Preliminary inspection responsibilities
- Inspection of preexisting conditions
- Inspection of surface preparation
- Inspection of mixing, thinning and coating application
- Post-application inspection
- Documentation and reporting

Preliminary Inspection Responsibilities

Depending on the particular project, the inspector may be tasked with a variety of actions prior to the commencement of work, including:

- Reading and understanding the project specification
- Reviewing drawings, reports, plans, and other project documentation
- Reviewing submittals from the contractor such as product data sheets, MSDSs, schedules, QA/QC plans, safety plans, etc.
- Reviewing reports, such as inspection reports from fabrication shops.
- Reviewing modifications of the contract
- Attendance at the pre-job conference
- Inspection of jobsite
- Inspection of equipment

The actual extent of the in-process inspector's involvement in these preliminary actions is solely a function of the of individual project management organization. In fact, an in-process inspector may not become involved until the coating application contractor has been mobilized and has started the work. Conversely, the in-process inspector may be given responsibilities beyond strictly coating inspection, especially in cases where the size of the project restricts the assignment of a full-time project manager/engineer.

At this point, it behooves us to view the in-process inspector's role in light of the project as a whole and question the feasibility and desirability of involving the inspector in all of the actions listed above.

The project specification refers to the technical requirements of the coating project. The overall project is guided by a contract, typically between the Owner and Contractor. The contract consists of terms and condition, specifications, drawings and a signed agreement. The collection of all these elements is commonly referred to as the Project Manual and is a legally binding document between the signatories. The in-process inspector's role is primarily to ensure the technical requirements are met and not necessarily be the interpreter of the intent, if there is any disagreement or conflict. Nor is the in-process inspector always qualified to pass judgment on submittals, change orders, reports and modifications to the contract. This is especially true if coatings represent only a portion of the specified work. Although an in-process inspector may be capable of such actions by virtue of accumulated experience, in-process inspector training programs may not necessarily provide sufficient training in this area.

The inspection of the jobsite and equipment may also be problematic. The in-process inspector may not be qualified to assess the conditions observed and may lack the authority (other than reporting) to act on any perceived deficiencies. In most contracts the application contractor is responsible for safety, quality of finished product, productivity, and selection of means and methods to meet specified requirements. The use of an in-process inspector (especially third party inspection) in areas other than assuring specification compliance may tend to blur the distinction between addressing technical requirements and evaluating the productivity of the contractor. In any event, the in-process coating inspector now assumes at least partial liability in the event of a coating failure or jobsite accident.[1]

There are numerous consensus standards and guides for defining the training, experience and responsibilities of in-process coating inspectors.[2-9] There are also several organizations that train and certify in-process coating inspectors, including:

- NACE International: After three training courses (each with an examination) and a peer review, in-process inspectors can attain certified status.[10] This program is the largest and most widely recognized certification body and extends internationally.

- The Society for Protective Coatings (SSPC): After a five-day training course and successful examination in-process inspectors can be certified as a NAVSEA Basic Painting Inspector, qualifying the inspector to perform quality assurance functions on U.S. Navy painting projects.[11]

- ACQPA/FROSIO Inspector's Certification: Certifies in-process inspectors to Norwegian standards.[12]

In-process coating inspection is viewed as a career ladder for painters capable of attaining the required training and certification. In the U.S., coating inspection for the most part represents seasonal work centering on the maintenance cycles of the industries affected. Third party inspection firms depend on a relatively limited pool of people and permanent employment with these firms is not the norm. Specifying bodies tend to focus on the use of certified inspectors, often ignoring the utility of those inspectors still in the process of certification. NACE International has trained approximately 10,000 people at the basic level and has certified approximately 2,000 inspectors. Active certified inspectors (those actually performing roles in coating projects) probably number around 1,000 – 1,200. There are few, if any, studies addressing the requirements for a workforce of third party inspectors to support the coating industry. Because of the inherent transitory nature of the work, in-process coating inspectors have not generated a "critical mass" in terms of recognition as separate professional cadre.

While anecdotal evidence exists to justify the costs of in-process inspection, the industry has developed few business models to objectively quantify the benefits. Coating inspection has been attributed as a major factor in reducing premature coating failures, by raising awareness of the need to address the factors necessary for effective coating installation. It appears that development of a more professional applicator workforce is being initiated, especially in government funded coatings projects. Raising the level of training of the person accomplishing surface preparation and coating application actions would appear to be advantageous to the industry as a whole. How these initiatives would affect in-process inspection remains unknown.

In terms of potential R&D efforts, the following broad areas should be addressed:

<u>Inspection of Preexisting Conditions</u>

The presence of certain contaminants and fabrication conditions may have adverse affects on the ability of a coating system to perform. These are best addressed before surface preparation activities, as the specified methods may not remove detrimental conditions. The in-process inspector's role involves investigation of the following conditions:

1. Presence of surface contaminants, both visible and non-visible.
2. Presence of fabrication and design defects and issues.

Surface contamination and fabrication issues are dependent on the substrate (especially when contrasting steel and concrete) and generally include consideration of the following:

- Surface pH
- Soluble salts
- Chlorides

- Ferrous ions
- Sulfate
- Grease or oil
- Weak surface layers
- Residuals from chemical paint removal operations
- Dust
- Welds and associated weld spatter
- Difficult to access configurations

There exist standards and guidelines to perform testing for the presence of contaminants and the existence of other potentially deleterious conditions.[13-20] Professional organizations have active committees addressing the needs of industry in developing new standards as the result of technological progress in the field of protective coatings. These organizations include:

- NACE International (NACE)
- The Society for Protective Coatings (SSPC)
- American Concrete Institute (ACI)
- International Concrete Repair Institute (ICRI)
- American Water Works Association (AWWA)
- American Society of Testing and Materials (ASTM)
- International Organization for Standardization (ISO)

However, there remain questions concerning the implications of the results of such testing, especially when considering the most often cited moieties in relation to premature failure, chlorides and residual dust (generated either during surface preparation actions or as the result of outside influences).

Various agencies have published maximum allowable concentrations of contaminants. It is presently unclear what rationales was used to establish these limits and whether or not there are differences in susceptibility of failure with different coating formulations. Finding potentially deleterious contaminants such as chloride (ubiquitous in the marine environment) is not surprising. Attaching the presence of these contaminants to specific failure modes is lacking, although generally speaking, osmotic effects are usually fingered as the culprit. The accuracy and precision of the various detection methods have not been emphasized generally. Efforts to remove such contamination can significantly increase the cost of a coating project.

Industry has responded to the perceived need to deal with soluble salts (especially chlorides) by the introduction of materials to sequester or otherwise render them innocuous to coating performance.

Dealing with design and fabrication issues, such as welds, sharp edges, and difficult-to-coat surfaces are, to this day, difficult to deal with because of the interaction of various trades and the emphasis on the most efficient structural design (which may not be compatible with optimum coating conditions). Typically, these issues are only addressed in more severe services, such as immersion.

Inspection of Surface Preparation

Once preexisting conditions are evaluated and dealt with, the coating contractor must prepare the surface to receive the specified coating materials. Generally, these actions involve the input of energy and may be both expensive and time consuming. The most studied substrate has been steel, but interest in the coating of concrete has initiated efforts in developing standards in this area. Dry abrasive blasting has been the method of choice for decades. Environmental and worker health and safety concerns have spurred the introduction of more advanced processes, such as high and ultrahigh water jetting. Evaluating conditions of the prepared surface is covered by a multitude of standards.[21-53]

Inspection of surface preparation on steel substrates focuses on two attributes:

1. Removal of contaminants that interfere with coating adhesion or that might induce premature failure.
2. Roughening the surface to promote coating adhesion (increasing the number of potentially reactive sites) often referred to as surface profile.

Inspection of surface preparation on concrete focuses on three attributes:

1. Removal of contaminants that interfere with coating adhesion or that might induce premature failure.
2. Roughening the surface to promote coating adhesion (increasing the number of potentially reactive sites) often referred to as surface profile.
3. Removal of weak surface layers that cannot support the stresses imparted by the coating system.

Inspection of Mixing, Thinning, and Coating Application

Modern protective coatings represent highly complex chemical technologies requiring specific knowledge for successful use. Coatings arrive at the jobsite in an unassembled form, and typically require specialized processes and equipment for effective application.

Economic considerations involving the loss of use of facilities is a strong driver in the introduction of rapidly curing coating materials. Environmental and worker health and safety are strong drivers in the introduction of materials with little or no solvents (added to formulations for application efficiency). Both of these forces have generated the development of "plural component" materials and application technology that has taxed the ability of the in-process inspector to adequately assure performance. In the past, mixing, thinning, application and cure of the coating material involved hours or days, allowing for a fairly long period to assess the adequacy of application. Technologies now exist where the mixing, application and cure occurs in seconds. Whether the focus should be on increased applicator sophistication or new inspection requirements is still being debated.

Post-Application Inspection

After application, the coating system is evaluated in terms of specification compliance in areas including:

- State of cure
- Dry film thickness
- Holiday (defect) detection
- Adhesive strength
- Appearance

Again, there are many standards covering these actions[61-77], as well as active committees that revise standards and initiate the development of new standards.

Documentation and Reporting

The in-process inspector generates a variety of reports on a daily, weekly and as-required basis. In addition to documentation in terms of specification compliance, these reports generally contribute to the success of the project by highlighting:

- Instances of non-conformance that may require resolution by project engineering or management personnel
- Objective determination of progress by the contractor
- Recommendations to improve project efficiency
- Coordinating the efforts of multiple parties in resolving disputes.

In-Service Inspection and Repair

The in-service inspection of coating systems (as well as other corrosion protection systems) is initiated to determine the need for maintenance (repair). The results of in-service inspection is invariably linked to maintenance budgets. Thus, there is a continual striving for balance between two extremes: on the one hand, maintenance organizations desire long periods of time between initial application and maintenance actions, conversely there is a point at which relatively minor maintenance can significantly increase a system's service life. Equitably resolving these extremes is difficult in practice. Prolonging intervals between maintenance periods risks damage to the substrate being protected (necessitating expense repair and replacement efforts). Performing maintenance too early wastes limited resources. Coatings have been determined to be an effective corrosion control strategy, and much emphasis in research focuses on improvements to materials and processes used in initial installation. Less attention has been given to the evaluation of existing systems to allow economically sound decisions within the overall maintenance perspective.

Given the three basic repair options discussed above, maintenance planners must determine:

- Is the existing system performing as expected? If not, what are the reasons for either a system performing below or above expectations?
- Given an existing condition, how long can maintenance be postponed?
- Which option provides the most economic results

Most in-service inspections are prompted by the need for maintenance planning. Typically, a "condition survey" is conducted to gain information on the:

- Extent of damage to the coating system
- Extent of deterioration to the protected substrate
- Flagging of unusual or unexpected conditions

The condition survey provides information on both the type of maintenance required and on the scope (quantity) of work involved. Estimates of project costs based on condition surveys are then incorporated into budget processes. A lack of information on condition can lead to highly ineffective maintenance decisions. The cost of the surveys can be substantial in large facilities or in widely dispersed facilities where logistic costs become a significant factor.

There exists a large support infrastructure for the in-process inspector. In-process inspectors have many tools to verify compliance with specified standards. In-process inspectors, in most cases, also have the advantage of well-defined criteria in terms of the standards being used.

The in-service inspector does not have comparable resources. In-service inspectors are commonly owner's personnel in operational facilities without specific knowledge of coatings technology. While consultants are available with expertise, the inspectors used for in-service inspection are often those specifically trained as in-process inspectors. It is generally perceived in the industry that the in-process inspector (especially one that is certified) can be used effectively during in-service inspection. This perception has several potential weaknesses.

The in-process inspector deals primarily with well-defined industrial processes (surface preparation and coating application), where the inspector may well have been an applicator previously. A large part of the in-process inspector's job revolves around effective communication with other project participants within a structured organization with many support resources. Contrast this with in-process inspection. The in-process inspector mainly deals with "things". The in-process inspector must look at a wide variety of elements, from structural steel to process equipment, and be able to assess their "condition". Most condition assessments are made based on grading systems. The grading system may incorporate just the condition of the coating or may include an assessment of the substrate. There are few industry-wide standardized grading systems, and where such systems exist (i.e., ABS, MMS), they are subject to debate as to the meanings of each grade, especially when the grades are only given written definitions.

The in-service inspector (or the agency using information gathered by the in-service inspector), has to determine the viability of repairs involving touch-up and refresh (touch-up and overcoat) operations. The operations are particularly problematic because the ability of the existing system to receive such treatment must be ascertained to avert potential failure. The ability of the system to receive this treatment is a function of the modes of deterioration, specific coating formulation chemistries, as well as the "structural integrity" of the existing coating. The science associated with determining this ability is still in its infancy.

The in-service inspector is also challenged to ascertain the economically useful remaining service life of an existing system and the consequences of loss of substrate. This involves consideration of factors not normally addressed in existing training programs, such as:

- Use of structural assessment protocols
- Implementation of economic models
- Risk assessment and management
- Evaluation of statistical deterioration models

- Consideration of alternate maintenance regimes
- Communication with engineering, programming, budgeting and contracting personnel

The materials and processes for the repair of coatings rely almost entirely on coatings formulated for application over blasted surfaces. The interaction of these coatings when used in repair processes may be detrimental to otherwise suitable existing systems, due to the stresses being imposed.

Summary

There exists a strong and active effort in the development of standards, guidelines and practices to support industry efforts in advancing technology development. This effort is accomplished by a variety of professional societies using consensus-based review by the major players: contractors, manufacturers, specifiers and owners. Major areas for R&D initiatives include:

Inspection of Coatings

- Conduct of cost/benefit analyses for coating inspection
- Elucidation of the mechanisms leading to premature failure of coating systems, especially in the area of surface contaminants
- Establishing consistent metrics for limitation of contaminants
- Increased emphasis on developing tools for in-service inspection
- Elucidation of the mechanisms of deterioration of coatings in service and the effects of this deterioration on remaining service life
- Establishing consistent metrics for evaluating coating in-service
- Developing procedures for inspecting application of rapid cure coating systems

Repair of Coatings

- Elucidation of the parameters essential for effective, long-term repair of coatings
- Development of tools to allow in-service inspector to quantify the parameters essential for effective, long-term repair
- Establish metrics for the determination of remaining service life
- Develop economic models for aiding in the repair decision making process
- Investigating the need for materials specifically formulated for touch-up and overcoat

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Past, Present and Future 'Smart' Protective Coatings

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Abstract

The best coatings for corrosion protection provide not only barriers to corrosion, but also a 'smart' release of a corrosion inhibitor as demanded by coating damage and the presence of a corrosive environment. Future development of protective coatings will take advantage of this aspect of coating technology. Past examples include coatings containing metallic zinc and chromate. Present and future efforts will take advantage of inherently conducting polymers as carriers for controlled release of inhibitors. Development of this technology requires an assay for evaluating the release of inhibitors from coatings.

Introduction

Historically, metallic zinc and chromate-containing primers have provided the excellent corrosion protection. Coatings made from these materials have properties that allow them to actively respond to the corrosive environment while maintaining a barrier to the environment. For a number of reasons, these coating have limited application particularly for materials used in aircraft manufacturing. New technology related to inherently conducting polymers (ICPs), battery technology, and drug delivery suggests approaches for engineering new 'smart' or damage responsive coatings. Here we review available concepts for 'smart' corrosion protective coating technology and describe recent progress as previously reported (1).

The demand to minimize maintenance of metallic structures while optimizing performance requires protective coatings that can self diagnose and respond to damage and changes in the external environment. Furthermore, the coatings must constitute no hazard to the environment and maintenance personnel and must be applied using conventional methods currently used to coat structures for environmental protection. New materials such as nano-structured materials and organic metals present opportunities for engineering damage-responsive coatings and structures. Such materials must be cost effective and non-hazardous.

Chromate and Galvanic Coatings

Among existing 'smart' coating technologies, chromate-containing coatings and galvanized coatings have been used over the last century or more. Chromate-containing coatings release the inhibiting hexavalent chromium when exposed to a corrosive environment (2-6). Release of this species passivates metal exposed at defects in the coating. The overwhelming success of chromate-containing paints and conversion coatings used over the last century and into the 21st century, despite the environmental hazard, can be attributed to its performance as a 'damage responsive' material. Xia et al. have reported evidence that the coatings release chromate not simply by mass-action dissolution from the coating, but as a result of electrochemical corrosion reactions that concentrate alkali at cathodic sites, thereby stimulating the chromate release (5).

Unfortunately, hexavalent chromium has limited use for corrosion protection due to its toxic and carcinogenic properties. Replacements must be found. Furthermore, the search for replacements must include a search for materials that will provide a damage-responsiveness.

Prof. G.S. Frankel provides a concise summary of the point made here regarding the responsive functionality of chromate:

"Actually CCCs [chromate conversion coatings] are already rather smart. They store an inhibitor, release it into aggressive solutions in which it migrates to an active site and irreversibly reduce to quench corrosive attack. Even duplicating the efficacy of CCCs is a considerable challenge (7)."

Besides chromate, the other old 'smart' or 'damage-responsive' coating technology that remains viable for certain applications is use of metallic zinc in coatings. Metallic zinc not only acts as a sacrificial material to electrochemically bias the substrate away from potentials where it anodically reacts, but it also generates a product, Zn (II) ion, that is corrosion inhibiting. Galvanized coatings are thus ideally 'damage-responsive' in that they will polarize a defect in the coating and in so doing release a corrosion inhibitor. The cost and weight of these coatings and their general ineffectiveness for the lighter alloys along with some concern for their environmental impact make them less than ideal for many aerospace applications.

Semi-conductive Coatings

In the mid 1980's the Naval Air Warfare Center supported development of a damage-responsive semi-conducting coating that would provide an electronic barrier at the metal coating interface (8,9). No practical application seems to have come from this approach.

Microencapsulated Inhibitors and Sol-Gel Coatings

The recent literature provides an overwhelming list of citations for sol-gel coatings used for corrosion protection. Notable in this list are those that include corrosion inhibitors, particularly when combined with the controllable microstructure and nano-structure of such materials (10). J. Osborne notes the similarity of the physical chemistry of sol-gel film formation and chromate conversion coating (11).

The ability of sol-gels to form nano-structures capable of encapsulating reagents (12) may lead to their ability to hold otherwise soluble inhibitors for release as a result of chemical or mechanical stress from the environment. Sol-gel structures have been used to encapsulate biomolecular catalysts (12). As such they help advance 'damage-responsive' protective coating technology. While locally formed increase or decrease in pH due to the onset of corrosion can trigger such mechanisms, the generally insulating properties of the oxidic coatings preclude a trigger that is purely galvanic. There are exceptions, of course. For example, sol-gel oxides can be conductive, as is the case of the vanadia aerogel considered for battery materials (13).

Related to this approach, Yang and van Ooij (13) have encapsulated soluble corrosion inhibitors using plasma polymerization. Such inhibitors can then be used in paints much as the conventional solid inhibitors are used. The inhibitor is slowly released as it diffuses through the thin polymer film. While this provides a mass-action governed release mechanism, it is a less selective process regarding damage-induced activation.

Also relevant to this discussion of damage-responsive coatings is the sol-gel coating that protects orthopaedic prostheses. Silica sol-gel films containing glass particulates can stimulate the growth of a protective apatite (15). This coating demonstrates an instance of a smart environmentally-responsive coating.

Stimulated Protective Bio-films

Some coatings may stimulate the formation of protective bio-films. For example, a recent note (16) suggests that biogenetically engineered bacteria may be able to release corrosion-inhibiting species such as certain polypeptides and polyphosphates. While this approach suggests an interesting process for active release of inhibitors, not clear is how it can be used for controlled release as a response to damage.

Ion Exchange Coatings

Ion exchange corrosion-inhibiting pigments have been considered for a number of years. The most recent work was that performed by Williams and McMurray, who demonstrated that hydrotalcite, rehydrated in the presence of inhibitor anions such as phosphate and chromate, provide excellent inhibition for filiform corrosion (17). The ion exchange pigments, when formulated in a paint, work to limit filiform corrosion in at least two ways:

- Lower the chloride activity through ion exchange with the inhibiting anion
- Buffer the anodic head of the filiform

Inherently Conducting Polymer (ICP) Coatings

Shortly after the discovery of conducting polymer materials, formed from highly conjugated aromatic ammines (Figure 1), DeBerry et al. demonstrated that in the conducting, oxidized form, such materials could anodically protect stainless steel in sulfuric acid by maintaining its potential in the passive region (18). Over the years, many have used this 'oxide-stabilization' model to explain the corrosion protection properties of polyaniline and other ICP or ICP-containing coatings on metals such as steel and aluminum exposed to various environments. As an example, B. Wessling provides a well-cited discourse on this hypothesis (19). Work describing the corrosion protective properties of ICPs has recently been reviewed by others (20,21) and will not be reviewed in further detail here.

While the anodic protection mechanism ('oxide stabilization' model) of DeBerry operates for stainless steel in non-chloride environments and other non-pitting situations, this mechanism is unlikely to explain the 'active' role of conducting polymer protection of steel in neutral chloride. Neither does it explain the corrosion protection of aluminum in chloride environments. In such cases, anodic polarization generally exacerbates pitting corrosion.

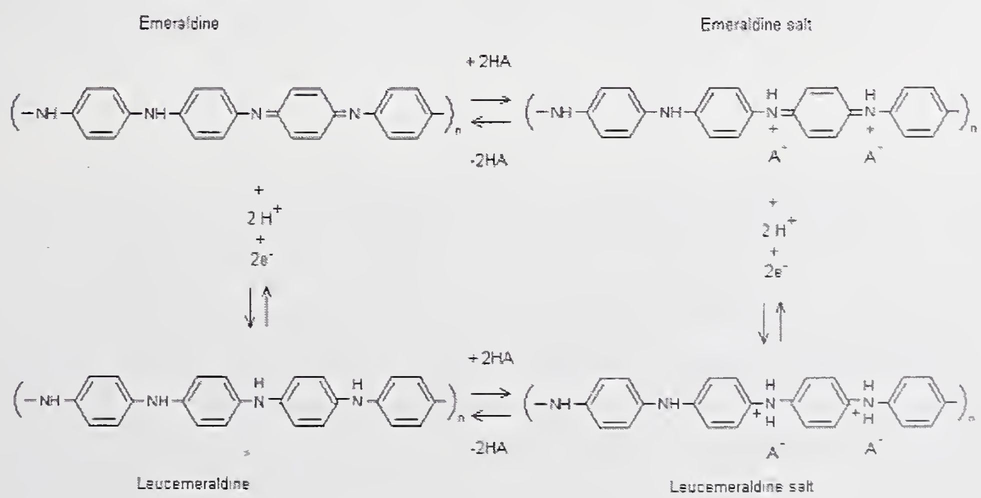

Figure 1. Oxidized and reduced, acid and basic forms of polyaniline (PANI).

Results from Cogan and co-workers (22) question the 'oxide stabilization' model with the observation that scribes primarily lead to the polarization of the coating rather than the defect for polyaniline (PANI) coatings on Al 2024-T3. They attributed the corrosion protection to the increase in the resistance of the polarized PANI film.

An alternative mechanism considers that the ICP becomes polarized through galvanic coupling to the base metal substrate at defects in the coating such that the ICP releases an inhibiting anion (Figure 2) (1). As shown in Figure 2, both cathodic reduction of the conducting polymer and ion exchange with cathodically generated OH^-, or both, can lead to the release of the anion dopant. When the anion dopant is a corrosion inhibitor, damage-responsive corrosion protection occurs.

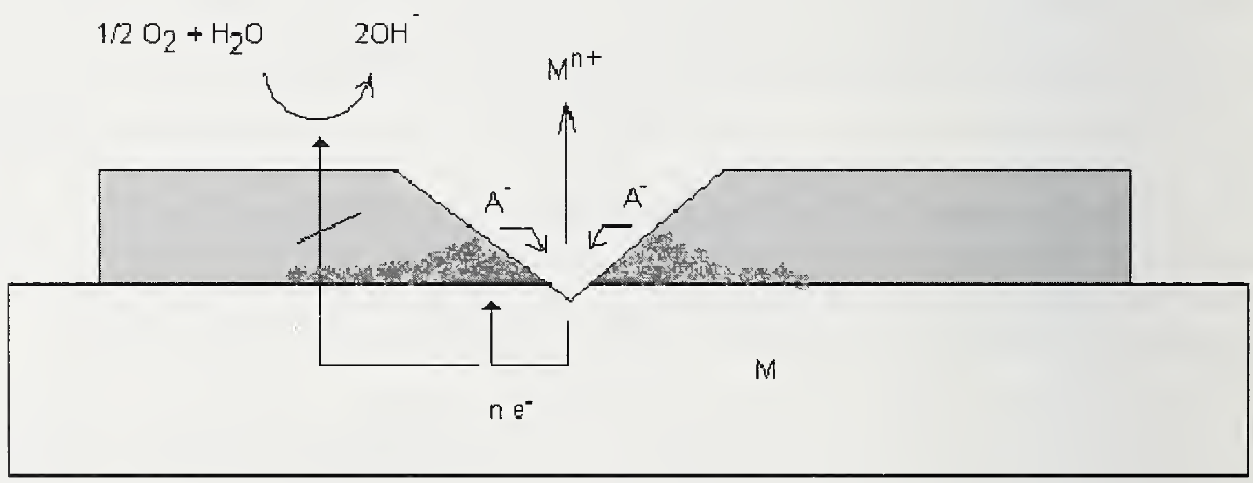

Figure 2. Schematic for a conducting polymer coating on a metal M that releases a corrosion inhibitor and ion A- upon being galvanically coupled to a defect in the coating (1).

Indeed, reports by Kinlen (23-25) et al. and deSouza (26) et al. have noted the importance of a dopant anion as an inhibitor. Kinlen (24) et al. used a phosphonate while deSouza et al. considered the inhibiting properties of camphor sulfonate, a typical dopant anion. At a recent Research in Progress (RIP) symposium sponsored by NACE, Tony Cook (27) also proposed the model of inhibitor release by the ICP as the mode of corrosion protection. Additional evidence from our laboratory reported recently (1) shows scribe inhibition by an ICP coating doped with an organic oxygen reduction reaction (ORR) inhibitor

(Figure 3). An extensive review of corrosion protection by ICPs also recognized the potential for an inhibitor-release mechanism (20,21).

While the original anodic protection model of DeBerry (18) operates for stainless steel in non-chloride acidic solution, one must remain skeptical of this mechanism for chloride rich environments where passivity typically does not occur. A better explanation for this latter case appears to invoke the presence of releasable dopants in the conducting polymers making ICPs clear candidates for damage-responsive coatings.

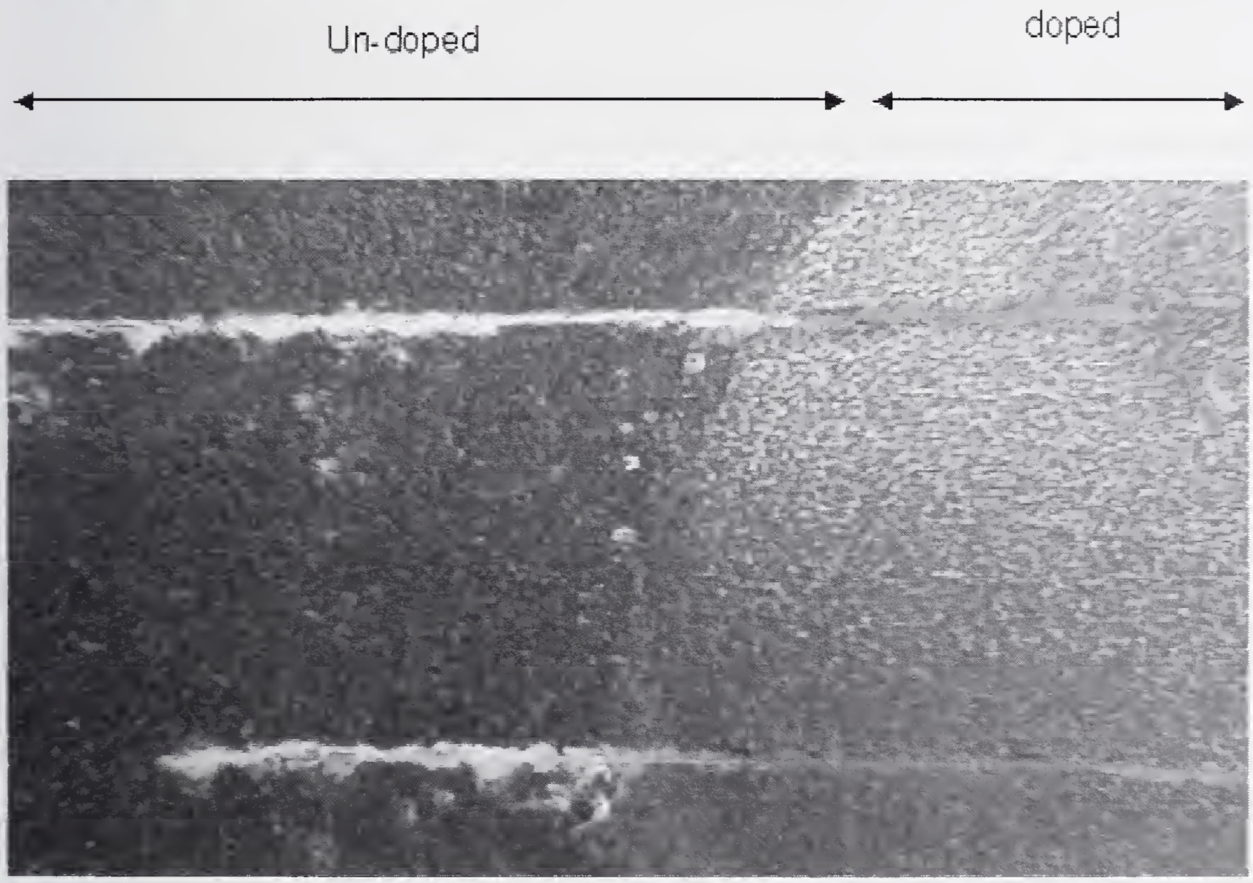

Figure 3. PANI coated Al 2024-T3 after 48 h of B117 salt fog exposure. The region to the right was doped with an organic anionic corrosion inhibitor (27).

Drug Release

The development of damage-responsive coatings, particularly those having properties for controlled release of a corrosion inhibitor can benefit from early research focused on drug release. Among the first to consider conducting polymers for this application was the University of Minnesota group of L.L. Miller who with B. Zinger provided the first example of the application of conductive polymers for the controlled release of biologically significant reagents. In 1984, they demonstrated the controlled release of ferrocyanide and glutamate from polypyrrole (28). Other anions that have been released under electrochemical control from ICPs include salicylate (29), and adenosine 5'triphosphate

(ATP)(30,31). This work begs the question, why cannot the anions that typically inhibit corrosion be incorporated as dopants in ICPs? Such anionic inhibitors may include phosphate, phosphonate, borate and nitrite as well as organic ORR anions.

Identification of Corrosion Inhibitors

Clearly protective coatings must release an effective inhibitor and provide a sufficient barrier to the environment. Both must work in concert. Neither an ideally hydrophobic coating that provides no protection for a defect nor a porous material that releases an inhibitor while transmitting water and ions poses an effective coating. Both of these requirements must be present. Electrochemical impedance spectroscopy provides an effective means for assessing the barrier properties of paints.

Recent work at Rockwell Scientific has led to a test that rapidly assesses the release of ORR (oxygen reduction reaction) inhibitors. Clarke and McCreery (32) showed that chromate functions primarily as an ORR inhibitor. Due to the fine distribution of a catalytic Cu-rich secondary phase cathode, the ORR, even for a scribed coated surface, remains critical to the corrosion of these alloys. For example, a scribe in a coated alloy will contain both the cathodic intermetallic sites where ORR occurs and anodic site of rapid dissolution. A coating that releases an ORR inhibitor can slow the entire corrosion process by inhibiting the cathodes that must reduce oxygen for the anodic dissolution to occur. Since the cathodes represent about four percent of the total surface area, it makes more sense to focus on an inhibitor that blocks the part of the corrosion reaction that requires these dilute sites. Based on previous work by Ilevbare and Scully (33,34), a Cu rotating disk electrode (RDE) placed at a precise location above the coating can detect the release of an ORR inhibitor through a decrease in the ORR current density. Even for ferrous materials in neutral aqueous environments, ORR at defects in porous rust layers governs the corrosion rate in a similar fashion (35).

The inhibition of the oxygen reduction reaction (ORR) may be expressed as the ratio of ORR current, Io, without the presence of inhibitor to I, that in the presence of the inhibitor. This ratio Io/I defines a particular ratio, R, when the diffusion length, δ (inversely proportional to the square root of the electrode rotation rate) equals 1 micron, a dimension typical of the catalytic cathodic phase.

Evaluation of solid corrosion inhibiting pigments in 1g/100 mL slurries of inhibiting pigment are made through a determination of the ORR current for a Cu rotating disk electrode (RDE) as a function of the inverse diffusion length in the absence of the inhibitor, in the presence of the inhibitor and after Cu RDE has been removed from the inhibitor slurry and placed back in a baseline inhibitor-free

electrolyte. From this data R may be calculated and the irreversibility of the inhibition determined.

For example, Figure 4 shows the current density at a Cu RDE cathode biased to –0.7 V vs Ag/AgCl in 5% NaCl as a function of the inverse diffusion length. The data appear for the RDE in the presence and absence of strontium chromate. Strontium chromate leaves an effective inhibition such that some suppression of the current remains after the electrode is placed back in uninhibited electrolyte.

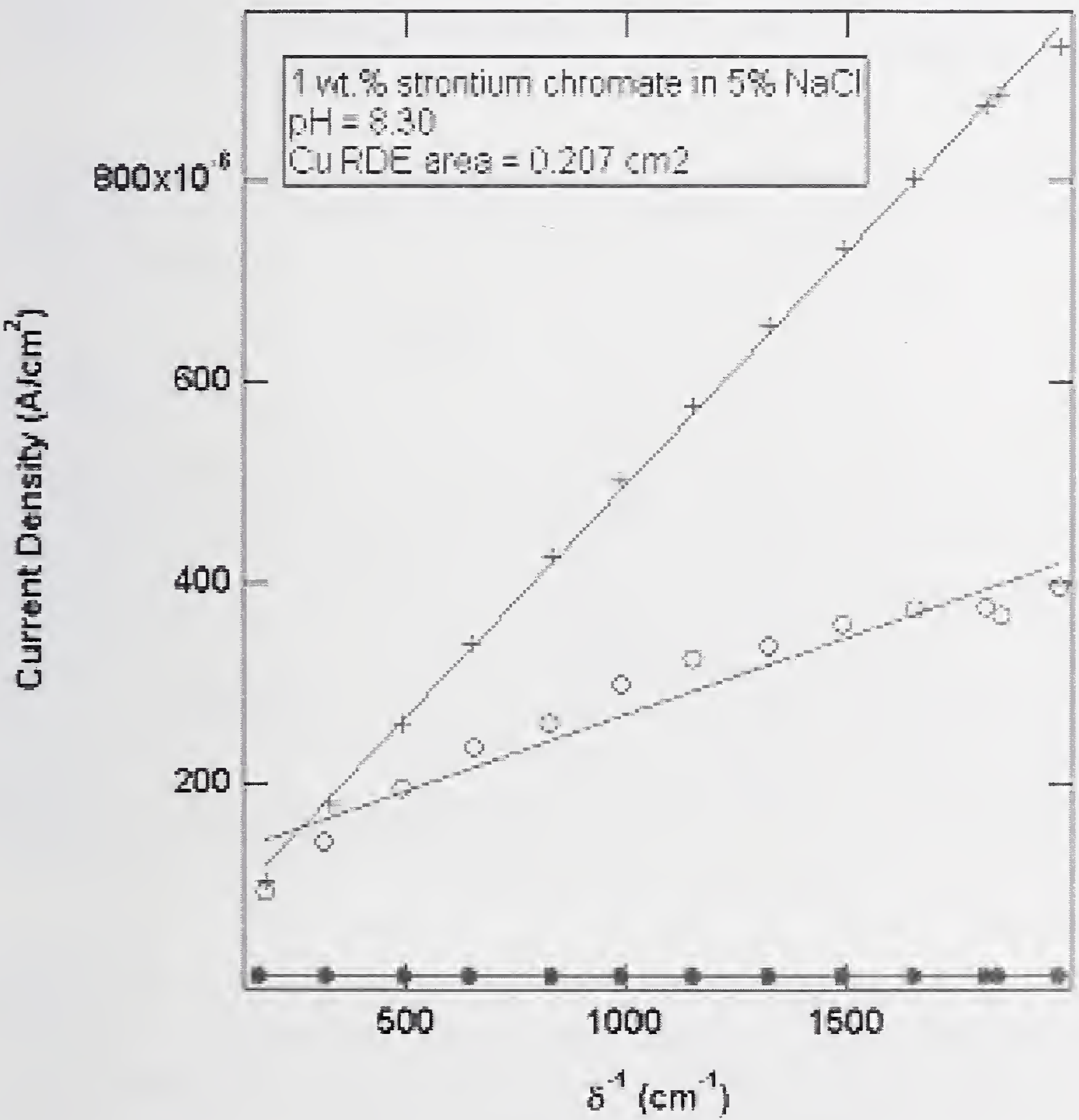

Figure 4. Cathodic current density appears as a function of 1/δ for a Cu RDE in 5% NaCl for the following conditions: no inhibitor (+), 1g/100 mL strontium chromate (•), RDE placed back in the baseline solution (°).

Often solid corrosion inhibiting pigments are formulated in paint. While the raw inhibitor may provide good inhibition of the ORR as slurry, the paint formulation may effectively deactivate the pigment by binding the releasable inhibitor too strongly or the inhibitor release by the coating may be degraded by some other means. The RDE assay for inhibitor release has evaluated release of an inhibitor

by flat panels using the test apparatus schematically shown in Figure 5. In this case the Cu RDE cathode, biased at –0.7 V vs Ag/AgCl in 5% NaCl and rotated at 2000 rpm, allows evaluation of Io/I. Prior to each coating evaluation, the Pt electrode was polished using fine abrasive (0.3 µm) and was electroplated at 30 mA/cm^2 with copper (2.0 µm thick) from a stirred copper pyrophosphate bath (55°C). This provided a reproducible Cu RDE cathode. The cathode is positioned at a reproducible distance (125 µm) from the coating surface using a linear motor controller. Immediately prior to measurement of the oxygen reduction current at –0.7 V vs. SCE, a cathode potential of –1.2 V was applied for sixty seconds to remove any oxide from the copper surface. For coating evaluations, the oxygen reduction current is typically measured after 1000 and 2000 seconds.

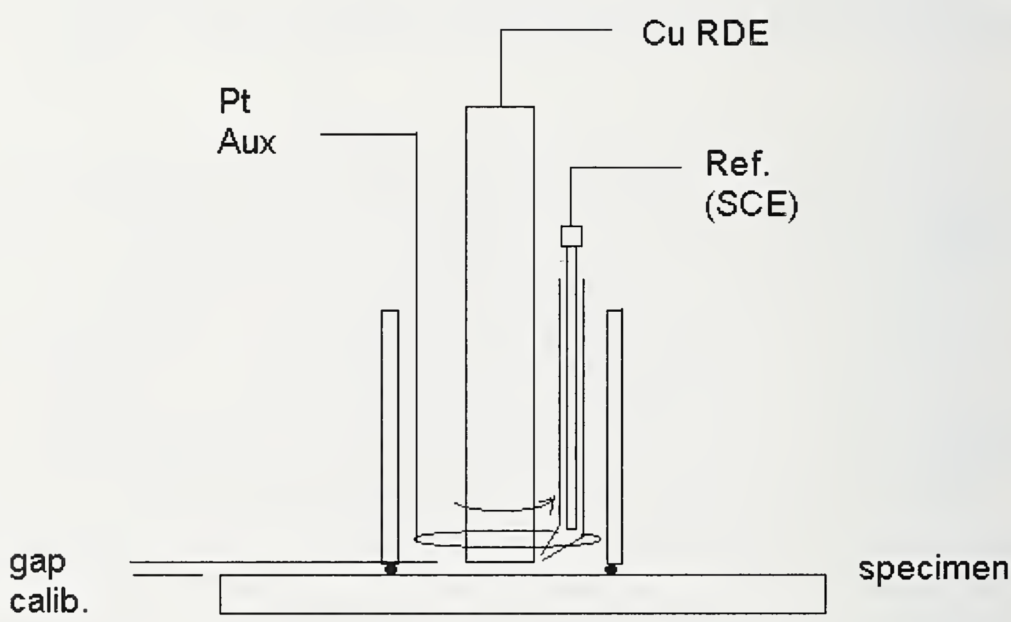

Figure 5. Schematic for the Cu RDE evaluation for ORR inhibitor release from a coating.

Figure 6 shows the current response for a freshly formed chromate conversion coating on Al 2024-T3 and one that had been deactivated by thermal degradation. The fresh coating released hexavalent chromium to suppress the current at the Cu RDE cathode, but the deactivated coating provides no such suppression.

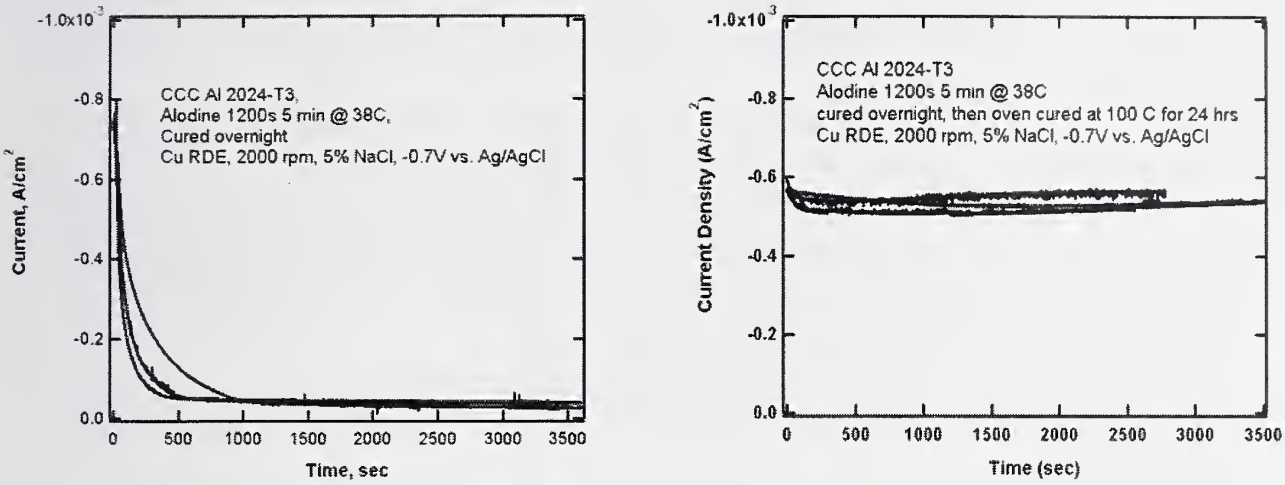

Figure 6. Cathodic current density vs time for a Cu RDE (2000 RPM, -0.7 V vs Ag/AgCl) above chromate conversion coated Al 2024-T3. The data on the right are for coatings that had been thermally deactivated.

Summary

To summarize, 'smart' corrosion protective coatings have existed in the form of chromate and lead-based primers and Zn-rich coatings. Such coatings provide more than a barrier against corrosion. For technical and environmental reasons, these traditional approaches will give way to new methods suggested by nano-technology, conducting polymer chemistry and drug release concepts that allow protective coatings to release corrosion inhibitors on demand. A key to exploiting 'smart' release of corrosion inhibitors from paints and coatings is a method for evaluating the ability of a formulated and applied coating to release inhibitor. A method for evaluating the release of oxygen reduction inhibitors from paints has been developed and proven useful.

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Risk Assessment and Economic Considerations When Coating Ballast Tanks

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Abstract

This paper will discuss the types of corrosion in ballast tanks, and areas within ballast tanks most susceptible to corrosion. An overview of the requirements regarding surveys and certification inspections will be outlined, and a coatings risk assessment methodology will be presented. Some of the causes of coating failure will be discussed, along with means to extend the life of shipboard coatings. Finally, a brief estimation of costs of coating ships and ballast tanks in new construction, and during maintenance and repair will be presented.

Introduction

Johnson [1] estimates the annual corrosion related cost to the U.S. marine shipping industry to be $2.7 billion. This cost is divided into costs associated with new construction ($1.12 billion), maintenance and repairs ($810 million), and corrosion related down time ($785 million). There are 9,321 tankers and carriers in service (oil tankers, chemical tankers, liquefied gas carriers, and ore carriers) which constitute 10.8 percent of the world's ships. These ships have a gross tonnage of 168,011,588 metric tons (185,200,000 tons), making up 34.8 percent of the worlds total ships by tonnage. Lloyd [2] states a typical 250,000 tdw double hull tanker has a total tank area of approximately 350,000 m^2 and a coated ballast tank area of over 200,000 m^2. Using these figures, it is estimated that the total ballast tank area in all tankers and carriers in service would exceed 135,000,000,000 m^2.

The environment within ballast tanks has been impacted by changes from single hull to double hull requirements resulting in a more severe corrosive environment, and diminishment of coating service life. Classification inspections have rigorous requirements regarding coating degradation, and the coating condition within ballast tanks must be closely monitored. Costs of maintaining

coatings and controlling corrosion on ships and in ballast tanks is a major expense, when both the costs of the recoating work, and associated down-time are considered.

New coating materials must be developed, along with new application techniques for those materials. Shipyards must be prepared to take the necessary amount of time to do a high quality coating application job during new construction, and anytime remedial coating work is done. The owners must recognize this need for utmost quality, and understand that the additional monies spent up-front for a better coating system will extend the service life of the coating and will be more economical over the long run.

Corrosion Within Ballast Tanks

On March 24, 1989, the Exxon Valdez ran aground in Prince William Sound, Alaska spilling 11 million gallons of crude oil. As a direct result, in 1990, Congress passed the Oil Pollution Act, which among other things, required all new tankers operating within U.S. waters to have a double hull. The double hull was used to insulate the cargo tanks from damage by providing both a primary and secondary containment in order to minimize, or hopefully eliminate any future spillage. The compartments within the double hull are used as water ballast tanks.

Initially, ship owners anticipated corrosion rates to be similar to those encountered in single hulled ballast tanks. It was known that repairs and steel replacement would have to be performed after the third special survey when the ship was 15 years old; however owners of the early double-hulled tankers found significant corrosion and pitting at the first special survey after only 5 years [1]. The reasons for the accelerated corrosion accrue to the use of higher tensile strength steels in the newer ships which allow for thinner plates that flex more than the carbon steel plates used in the older tankers. Also, when a hot cargo, such as crude oil loaded in the Middle East, Africa, South Pacific the Gulf Coast and other high temperature regions, the cargo heats the ballast tanks. Without a double hull, the cargo would be cooled by seawater on the opposite side of the single hull. However, the double hull void space insulated the cargo, slowing its cooling. Ballast tanks, even when empty, have water (and often silt) in their bottoms, and condensing humidity throughout. The elevated temperature of the cargo increases the rate of corrosion within the ballast tanks, doubling it for every 10°C increase in temperature. Thus if the average temperature of a ballast tank is 20 °C warmer than previously, the corrosion rate would be quadrupled.

Cracking of paint due to brittleness or loss of flexibility with ageing is considered a primary factor in corrosion damage to the steel structures of ship's hulls, notably in seawater ballast tanks. This cracking is typically found in areas of coating stress concentrations such as sharp angles, fillet welds, transitions

between structural details, weld toes, etc. Cracking is more severe for structural details made of high strength steel than for normal strength steel. This cracking is because thinner sheets of the high strength steel are used, and the lesser thickness results in greater flexing when the vessel is underway in rough seas.

Lloyd [2] identifies areas of local areas of high stress in transverse web frames. Areas of concern are at the end of brackets, toes and similar connections; ends of spans; and connections between longitudinals and web frames. These areas are depicted in Figure 1 below.

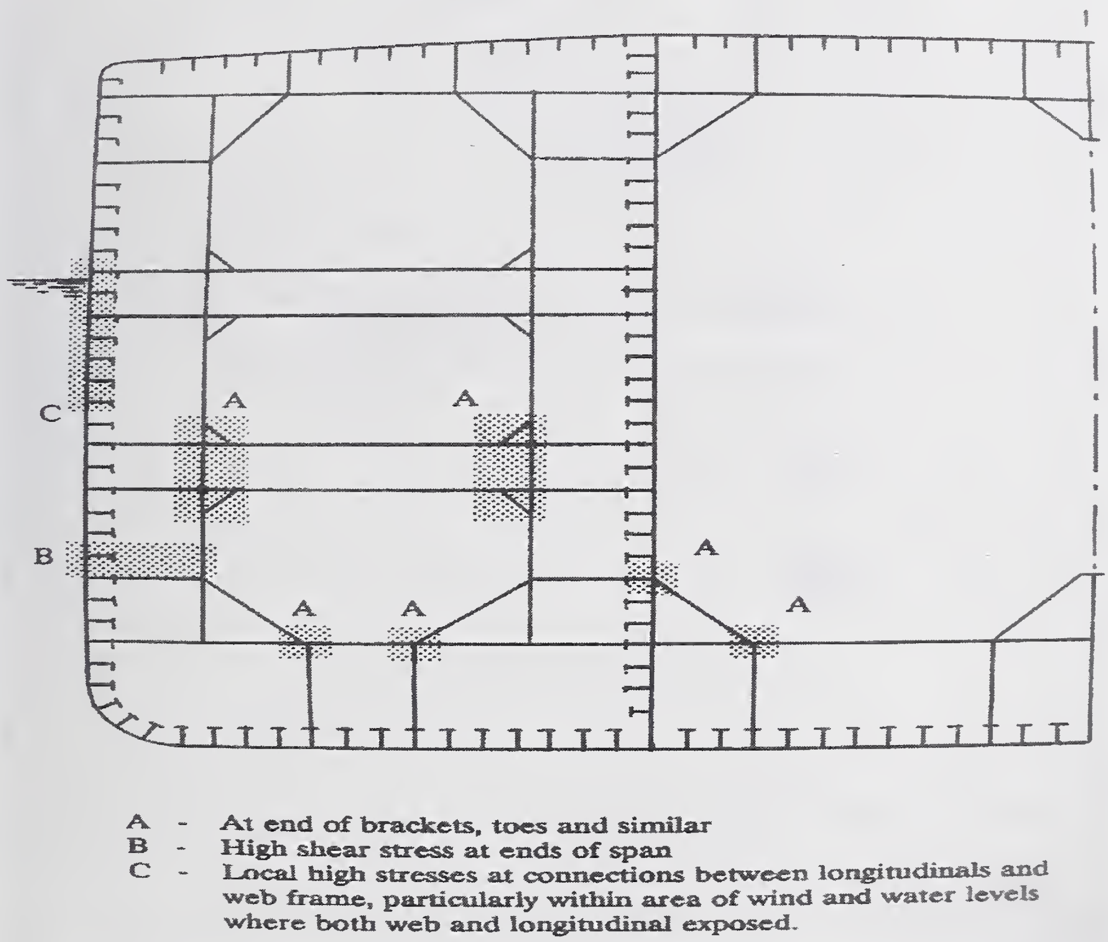

Figure 1: Schematic of longitudinal and web structural members in an oil tanker.

Lloyd also identifies areas of corrosion on the bottom plating of ballast tank steel. Areas of heaviest steel loss occur adjacent to the cut-outs in longitudinals, and at cut-outs of transverse web frames on the bottom deck plating. Moderate steel loss areas cover most of the bottom deck plate steel, particularly where there is opportunity for water flow through the cut-out areas. Pitting occurs on the horizontal surfaces of most members. Vertical sections of web frames and longitudinals are least affected by corrosion. These areas are depicted in Figure 2:

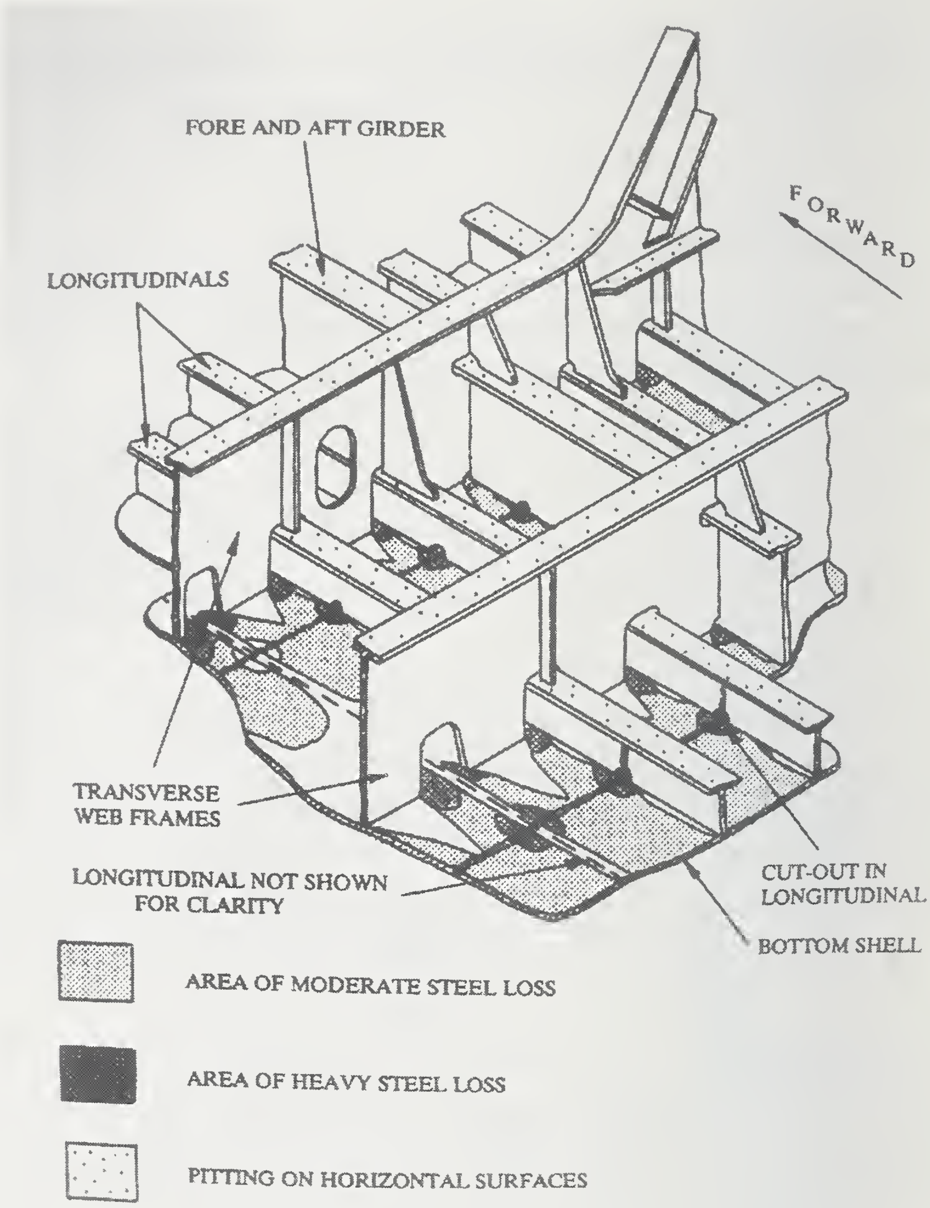

Figure 2: Areas of specific tank corrosion.

Causes of Coating Failures

Coatings fail for a number of reasons, but by far, the principal reasons for coating failure are deficient surface preparation and insufficient coating thickness. However, these application-related failures are readily observable and/or detectable at the time of surface preparation and coating application. With a conscientious paint contractor, and good independent inspection, surface preparation and coating thickness deficiencies can be readily corrected.

Surface preparation in ballast tanks, both for new construction and maintenance is difficult, time consuming and expensive. It is necessary to remove all impurities and old coating, and anything else that may interfere with adhesion and performance of the ballast tank coating system. In new construction in the

U.S., the length of the ship construction sequence is usually long enough for rust through and corrosion to commence through the pre-construction primer. Moreover, the act of cutting, welding and general construction activity provides for contamination of the pre-construction primer with weld spatter and oily residues from weld fluxes and fumes. As most shipyards are close to the ocean, salt deposits on the steel and coating are almost unavoidable. All these contaminates must be removed in order for any coating applied to the steel, or over a pre-construction primer to attain optimum service life. To enable coating adhesion, not only must the surface be properly cleaned, but there should be suitable surface roughness, or anchor pattern, to enable adequate adhesion of the coating, particularly if there will be flexing or vibration of the steel substrate.

Application of each coat of the coating system must be done properly and to sufficient thickness. When observing failures within ballast tanks, there is far more corrosion on edges than there is on plate steel. Because all liquid applied coatings draw thin over sharp edges and protruding irregularities, these areas need to be stripe-coated. Paint “daubing” brushes, generally round, fine bristled brushes that can hold a lot of paint are often used to stripe-coat rat holes, cutouts and other irregularities in order to apply a greater paint thickness. Stripe-coating is usually done after the first full spray coat has been applied to the blast-cleaned steel, or over the pre-construction primer if it is not removed. Striping may be done either before or after application of each subsequent coat of paint. The “mechanical” action of the brush bristles working the paint into irregularities, and displacing any remaining dust, dirt or debris from the surface is an important factor in obtaining good adhesion. Also, where there are inside angles and corners, pits and other recessed areas, the bristles of the brush work the paint into the depressions much better than a spray application.

When the coating has been properly applied to a properly prepared surface, stress in paint films is a major factor in coating failure, usually resulting in cracking, peeling, or disbonding. Such stress occurs as a result of:

- Shrinkage due to chemical curing and cross linking of the epoxy lattice. This linear shrinkage upon initial cure is relatively low for bis-phenol A epoxies, usually about 0.6%. More highly cross linked novolacs and cresols that are becoming increasingly common have a much higher shrinkage rate.
- After-shrinkage due to migration and loss of low-molecular components from the coating film. Migrating low molecular weight plasticizers are particularly responsible for this, particularly if the coating is exposed to elevated temperatures.
- Environmental impacts (mainly chemical degradation but also stress). Oxidation and degradation of the paint film caused by reactions with air; cyclical water up-take and drying; and hydrostatic pressures and flexing due to ballasting and deballasting.

- Strain in the steel substrate, particularly increased flexing as a result of the use of thinner plate sections of high yield strength steel.
- Mechanical impacts such as direct and reverse impact from use of heavy loading equipment, or tool impacts.
- Loss of entrapped solvents that did not volatilize while the coating was drying due to low application or curing temperatures.

Mills [3] has seen osmotic activity in the “anode” areas of welding heat-affected zones within ballast tanks. Here the weld metal is cathodic to the adjacent heat affected zone of the steel plate. These areas may not be able to be cleaned as well, and may also be hardened by the heat. Blistering may form over the heat-affected zone adjacent to the weld. The coating over the weld remains unblistered, with good adhesion.

Mills also does not recommend the installation of anodes in newly fabricated ballast tanks, although he recommends the installation of anode brackets for later anode installation when coating breakdown warrants their use. Anodes are only operative when the ballast tank is filled. When the tanks are empty, the anodes cannot function. Anodes and zinc holding shop primers do not go well together. Zinc is amphoteric (soluble in both low and high pH solutions) and dissolves in the high pH solutions that develop upon reduction of oxygen (at the cathode). While corrosion of steel does not occur due to the high pH, the dissolved zinc forms tetra hydroxyl zincate ions [$Zn\ (OH)_4^{=}$]. These ions drive the osmotic destruction (blistering) of the coating as any ionic contamination will do.

Of course, all of this presumes that the proper coating system for the ballast tank environment is chosen and applied correctly. An unsuitable system, no matter how well applied, will fail and an excellent coating system poorly applied may fail even faster.

Surveys and Certification Inspections

The International Association of Classification Societies (IACS) document “Requirements concerning Survey and Certification” [4] rev 2004 is a 402 page document consisting of 27 sections covering hull and classification surveys of oil tankers, bulk carriers, chemical tankers, double hulled oil tankers, double side skin bulk carriers and general dry cargo ships, and other marine vessels, machinery, hatch covers and coamings, propeller and shaft tubing and other features critical to marine vessels.

Hull Classification Surveys (Special surveys) must be carried out every five years to renew the Class Certification. The scope of the survey is to ensure that “...the ship is fit for its intended purpose for the next 5 year class period, subject to

proper maintenance and operation and the periodical surveys being carried out at the due dates" (2.2.1 page Z7-3).

Some relevant definitions are as follows (from pages Z7-2 and Z7-4):

1.2.5 Suspect areas are locations showing Substantial Corrosion and/or are considered by the Surveyor to be prone to rapid wastage.

1.2.6 Substantial Corrosion is an extent of corrosion such that assessment of corrosion pattern indicated a wastage in excess of 75 percent of allowable margins, but within acceptable limits.

1.2.7 Protective Coatings are to usually be epoxy coating or equivalent. Other coating systems may be considered acceptable as alternatives provided that they are applied and maintained in compliance with the manufacturer's specification.

1.2.8 Coating Condition is defined as follows:
GOOD-condition with only minor spot rusting
FAIR -condition with local breakdown at edges of stiffeners and weld connections, light rusting over 20 percent or more of areas under consideration, but less than defined for POOR condition. POOR-condition with general breakdown of coating every 20 percent or more of areas or hard scale at 10 percent or more of areas under consideration.

NOTE: The definition of "Good", "Fair" and "Poor" is under review at the time of this writing. The cut off for annual inspection may soon be FAIR (or "NOT GOOD) as opposed to POOR as in the past.
The bottom limit of GOOD may be interpreted to be:
General coating breakdown less than 3 percent
Edge and weld coating breakdown less than 20 percent
This limit is for the ship's life. This means that a greater coating breakdown than 3 percent (in 20 or even 25 years) will cause problems!!

2.2.7 For spaces used for salt water ballast, excluding double bottom tanks, if there is no protective coating, soft coating or POOR protective coating condition and it is not renewed, maintenance of class is to be subject to spaces in question being internally examined at annual intervals. Waiver of internal examination at annual intervals for tanks of 12 m^3 or less in size, with soft coating, may be considered.

2.2.8 When such conditions are found in salt water ballast double bottom tanks, maintenance of class may be subject to the spaces in question being internally examined at annual intervals.

2.2.11 Thickness measurements are to be carried out in accordance with Table 1 "Minimum Requirements for Thickness Measurements at Special Surveys" (not included in this paper). Additionally, any part of the vessel where wastage is evident or suspect, the Surveyor may require thickness measurements in order to ascertain the actual thickness of the material.

2.2.12 When thickness measurements indicate Substantial Corrosion, the number of thickness measurements is to be increased to determine the extent of Substantial Corrosion. Table 2 (below) may be used as guidance for additional thickness measurements.

Table 2: GUIDANCE FOR ADDITIONAL THICKNESS MEASUREMENTS IN WAY OF SUBSTANTIAL CORROSION

STRUCTURAL MEMBER	EXTENT OF MEASUREMENT	PATTERN OF MEASURMENT
Plating	Support areas and adjacent plates	5 point pattern over 1 square meter
Stiffeners	Suspect area	3 measurements each in line across web and flange

4. Intermediate Survey

4.1 Schedule-The intermediate survey is to be carried out at or between the second and third Annual Survey.

4.2.1 The scope of the second or third Annual Survey is to be extended to include the following:

4.2.1.1 For vessels over five years of age, a general, internal examination of representatives spaces used for salt water ballast is to be carried out. If there is no protective coating, soft coating, or POOR coating condition, the examination is to be extended to other ballast spaces of the same type.

4.2.1.2 For vessels over ten years of age, a general, internal examination of all spaces used for salt water ballast is to be carried out.

4.2.3 For spaces used for salt water ballast, excluding double bottom tanks, if there is no protective coating, soft coating or POOR protective coating condition and it is not renewed, maintenance of class is to be subject to spaces in question being internally examined at annual intervals. Waiver of internal examination at annual intervals for tanks of 12 m^3 or less in size, with soft coating, may be considered.

In summary, ballast tank coatings are subject to rigorous inspections that increase both in scope and frequency even if the coating condition is satisfactory (good or fair).

Risk

The identification of hazards and prioritization of risk is essential to a successful risk management program. What are hazards? A hazard has the potential to cause harm or damage. What is risk? Risk is a combination of the likelihood of the hazard happening, and the consequence of that happening. In order to assign risk, the hazard has to be identified, its probability estimated, and the consequence assessed. API [5] has developed a matrix for a risk-based index (RBI) shown in Figure 3:

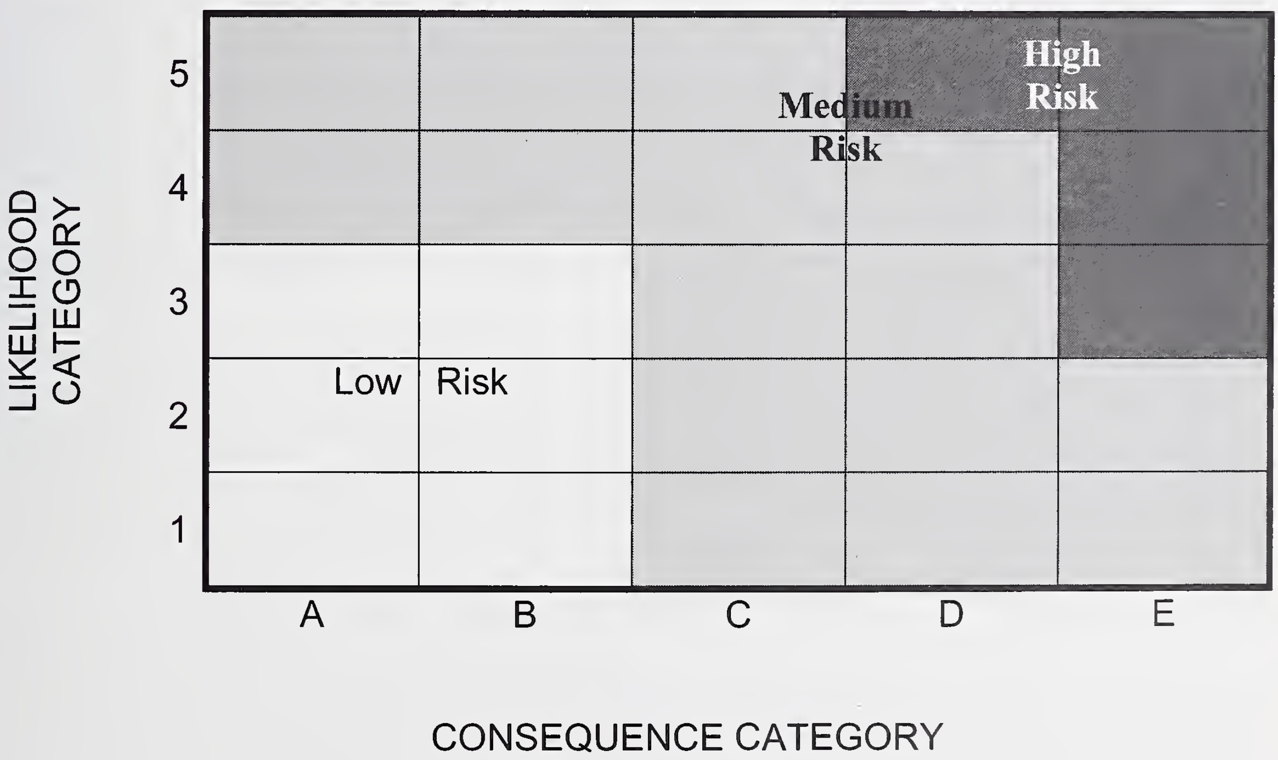

Figure 3: Risk based index (RBI) matrix.

As can be seen, the Risk is assigned into categories of 'high', 'medium' and 'low' based upon their likelihood of occurrence and consequence. This enables a prioritization of Risk, and the risk assessment methodology to inspect, evaluate and control it (described in outline form below).

Risk Assessment Methodology

Risk Assessment is subset of a corporation's overall policy and procedure for proactively managing a facility for health and safety issues. The steps necessary to establishing a successful Risk Management Policy, adapted from Capcis [6] are outlined as follows:

1. Establish the Corporate Policy-upper management must decide what their tolerance/position is for a given risk. It is essential that upper management "buys-into" whatever policy is decided upon, for implementation will require time and money.
2. Convene an Organization/Staff-individuals who are knowledgeable, concerned and involved must be assigned, and their supervisors must concur that appropriate time and effort can be delegated to risk management.
3. Planning and Setting Standards-planning is based upon long-term strategies and objectives (as developed in step 1). The planning needs to develop a systematic means to accomplish the strategy as measured by the objectives. Standards need to be established, usually based upon company guidelines, industry standards, and governmental requirements. There needs to be an acceptance criterion, which will be used to measure performance against the standards. The acceptance criteria need to be realistic, measurable and achievable.
4. Performance Measurement-inspections, surveillance and observations, in a systematic fashion, as developed in Step 3 needs to be done in order to establish conformance with the acceptance criteria that has been established. This step can be very time consuming, and require a lot of documentation that will need summation and analysis in order to determine whether progress is being made toward proper management and control of risks. Two types of monitoring systems are used: Active Monitoring (checks and inspections) on an on-going basis to assess conformance with the acceptance criteria; and Reactive Monitoring, or "after failure-post mortem" examinations to determine what went wrong, and how to avoid a repeat of the problem.
5. Audit and Review-the performance measurements outlined in Step 4 must be assessed to determine if the acceptance criteria have been met and management of risk has been successful. The process needs to be audited and updated on a periodic basis to remedy problems in the process that may make it less effective.

Means to Extend Coating Life

Because of the problems described above, there is concern regarding the longevity of ballast tank coatings and the high costs of repair/replacement. A number if diversified ship owners have expressed concern and made recommendations regarding their approach to resolve the longevity problem.

Eliasson and Mills [7] conclude the most appropriate time to fully and properly coat ballast tanks is at the new construction stage. They contend that presently used fast curing and low temperature coating systems are not sufficient, and challenge the coating manufacturers to develop new long lasting coatings possibly based upon hot amine cured 100 percent novolac epoxy resins. They also suggest an application sequence that should allow shipyards a faster throughput.

Webb, Brinkerhoff, Rice and Bizol [8] describe the U.S. Navy's use of high solids coatings and plural spray equipment to reduce preservation costs and the adverse effects of painting operations on the environment. The U.S. Navy advocates the use of new "edge retentive" coatings that build to higher thicknesses on sharp edges and protrusions than conventional epoxies. These new materials have a short pot life and/or require heating. Accordingly, plural component spray (where the coating components are proportioned and mixed either immediately before the spray gun, or by impingement during spray application) must be used.

Shell International Trading and Shipping Company Ltd. [9] provides an overview of Tank Structural Co-Operative Forum (TSCF) guidelines for a 10, 15 and 25-year system specification. All systems require initial surface preparation to Sa 2½ (near-white blast cleaning) with a 30-75 micron profile. Soluble salts are limited to 30 mg/m^2. A pre-construction ethyl-zinc silicate primer is specified.

- For the ten year system, Preparation grade P1, one pass edge grinding, Sa 1 (brush-off blast cleaning) removal of 30 percent of the pre-construction primer, and Sa 2½ at damaged areas and welds is required, followed by 250 micron minimum dry film thickness of a light colored epoxy applied in a minimum of one full stripe coat and two full spray coats.
- For the fifteen year system, Preparation grade P2, three pass edge grinding, and Sa 2 (commercial blast cleaning) removal of 70 percent of the intact pre-construction primer, and Sa 2½ at damaged areas and welds is required, followed by 300 microns minimum of a light colored epoxy applied in 2 full stripe coats and two full spray coats.
- The twenty-five year system requires Preparation grade P2, edge grinding to radius and Sa 2 ½ removal of the pre-construction primer. Application of a light colored epoxy to 350 microns minimum in three full stripe coats and three full spray coats is required.

The Naval Surface Warfare Center, Carderock Division [10] is currently investigating the following methods and materials for ship preservation:

- Improved high solids epoxies
- Thermoplastics and powder coatings
- Composite materials
- Thermal-sprayed aluminum
- Ultra-violet (UV) cured coatings
- 100% solids-high build coating systems

There are a number of interesting possibilities for improvement of coating systems and application methodologies to improve ballast tank coating service life, reduce costs and minimize environmental impact.

Costs of Coating

Johnson [1] estimates that for new ship construction, the coat for coating most ships is seven percent of the total cost of the ship. This, however, includes all coatings, not just ballast tank coatings. While the cost to apply a proper coating is expensive, it was four to fourteen times more expensive to replace corroded steel than to apply a coating during construction, and maintain that coating. The cost of coating oil tankers was estimated higher, at ten percent of the ship's construction cost. This is because better coatings are required due to the presence of hydrogen sulfide in crude oil. Johnson also estimated the annual repair and maintenance costs, including down time, for corrosion protection (mostly coatings, but also all other forms of corrosion protection such as anodes, metal replacement, etc.), for ships classified as follows:

- Oil Tankers $340,000
- Chemical Tankers $440,000
- Bulk Dry Carriers $106,000
- Cargo Roll-on/Roll-off $123,000

Johnson further estimates the costs of solvent-free epoxies to be, on average, $6.60 per square meter, compared to coal tar epoxies and solvent-borne epoxies that cost, on average $1.80 and $2.80 per square meter respectively. For the amount of coating needed to coat a ship, it is approximately $150,000 more expensive to use a solvent-free epoxy over coal tar epoxy, and $120,000 more expensive than use of a solvent borne epoxy. However, he states that the additional $150,000 spent during construction can pay major dividends during the operational life of the ship. If the cheaper coal tar epoxy coating is used during construction, the coating will have to be reapplied two or three times over the estimated twenty-five year life of the tanker. To perform the re-coating, the tanks

would first have to be cleaned and grit blasted before the coating is applied. The total cost of such a job on a large tanker would be approximately $3 million.

Eliasson and Mills [7] state that "to recoat a double skin Very Large Crude oil Carrier (VLCC=2 million barrels=280,000 tons) with 250,000 m^2 in the ballast tanks would take 250 days and cost about $20 million" including down time.

Webb, Brinckerhoff, Rice, and Bizol [8] state that the high-solids coating materials used in their study cost typically $38/gallon compared with roughly $20 / gallon for solvent borne epoxies. Waste disposal costs at one naval facility were $0.12 per pound for solidified epoxy waste, and $1/pound for solvent bearing waste. Overall, the one-time application costs of the high-solids epoxy paint system, with an estimated service life of twenty years, increased from approximately $5.70 to approximately $6.25 per square foot ($62 to $69 per square meter) exclusive of labor, or approximately ten percent over the cost of applying a conventional epoxy polyamide system.

In summary, new coating materials must be developed, along with new application techniques for those materials. Shipyards must be prepared to take the necessary amount of time to do a high quality coating application job during new construction, and anytime remedial coating work is done. The owners must recognize this need for utmost quality and timely maintenance, and understand that the additional monies spent up-front for a better coating system will extend the service life of the coating and will be more economical over the long run.

Acknowledgment

The author is indebted to his good friends Johnny Eliasson, Materials Protection Project Manager for Stolt-Nielsen Transportation Group B.V., Schiedam, Netherlands; and Dr. George Mills of George Mills & Associates International, Inc., Houston TX for their assistance and timely review with pointed constructive comments during the preparation of this paper.

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Decision Making in Coating Selection in Marine/Offshore Environments

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Introduction

Given the myriad of possible choices, selecting a coating system to protect an offshore structure, a marine pipeline, or a ship from corrosion damage is a difficult decision. Selection includes a number of coating systems, which address many different components from structural components, piping systems, static pressure equipment (tanks and vessels), power systems (compressors and pumps) and a multitude of instrumentation and electrical infrastructures.

In order to make a practical, cost-effective recommendation, the selector must solicit and synthesize input from multiple sources, many of which have competing economic agendas. He/she must consider the coating's basic function, i.e., corrosion protection, aesthetics, etc., as well as technical subjects such as the coating's compatibility with the service environment, the coating's physical and mechanical properties, and accessibility to the structure in time and space,

environmental factors, and life-cycle costs. Additionally, he/she must consider whether the substrate to be protected is new, previously coated, or corroded. Since no one protective coating is suitable for all potential applications, selection of a coating for a particular application always means balancing economic and technical considerations to achieve a solution, i.e., coating selection is a compromise.

Despite these difficulties and the importance of coating selection to the long-term integrity of offshore installations, coating selection is often carried out by non-specialists who use largely subjective and undocumented procedures. Misapplication may result in poor coating performance, premature failures, increased life-cycle costs, and missed business opportunities. The authors of this paper attempt to provide some basic approaches to coating system selection. Selection is a dynamic process, and one should always seek a better approach-looking for the best way of selecting a coating system that works for new construction and maintenance coating projects for any equipment whether a marine vessel, floating production facility, fixed or floating platform or simple pipeline.

The Cost of Corrosion

Therefore, let's first look at the cost of corrosion before moving on to decision making and the technical and economic factors that affect coating selection. Various estimates exist with respect to the cost of corrosion. Cost tracking include the following:

- 1950s – UK $1.25 billion
- 1980 – USA $5.5 billion
- Approximately 4% of USA GNP ($276B)

Approximately 40 million gallons of high-performance paints were sold in 1979. The offshore structures protected by these coatings largely represent the world's oil and gas production and transportation facilities, the value of which are increasing at a rapid rate, making good coating selection a necessity rather than a luxury.

The cost of poorly made coating selection is often high. Looking at how coating selections are typically made, justifies the need for an improved approach.

The Decision-Making Process

The following are typical answers received when one asks how to make coating selections:

- Use what we always use
- Do what others are doing in the same or similar industries and perhaps change when others apply the applications (Always be safe and second)
- Use what is dictated by global purchasing agreement
- Use what the supplier/manufacturer recommends
- Use lowest price coating
- React to failures and rumors or failures

Contrasting and comparing these coating-selection methodologies with some classical decision making techniques begins the process selection and is another step forward. In his book "The Art of Making Decisions", Wire Assessing reviews typical ways that people make decisions:

- Pray/ask fortune tellers
- Dictatorial/Monarchial
- Egotistical
- Delegate to Subordinates
- Pass the Buck
- Rely on Gut Feelings
- Postpone
- By Consensus
- Follow Tradition/Superstition/Established Rules
- Pattern Recognition
- Gambling
- Heuristics
- Mathematical Decision Analysis

The methods used run the gamut from humorous to serious and from simple to highly complex. However, as shown in the table below, in the final analysis the decision-making process used in making technical decisions does not differ much from the methods used everyday in making non-technical decisions.

Is there a better way? Yes, there is a better way. How complex does the process need be to be judged useful and successful? Is there a way to calibrate or validate our decisions? The level of complexity required in the decision-making process depends on the context of the decision. The level of "calibration" or validation required of a particular decision depends on the overall level of risk.

Table 1 Decision Making Comparison

Pray/Ask Fortune Tellers	Supplier/Expert Recommendations
Dictatorial/Monarchical	Global Purchasing Agreements
Traditional/Established Rules	Use What We Always Used
Gut Feelings/Gamble	Change for the Sake of Price or Convenience
Delegate	Follow Lead of Others/Consultants

One way to judge the necessary level of complexity is to consider the context of the decision, which may run from the mundane to extremely challenging or one from where there are no major stakeholder implications to one where society itself has a stake in the outcome. Obviously, the level of validation and calibration required of any coating decision needs to be matched with the context of the decision. Whereas simple comparison to existing codes and standards may be acceptable for low-level decisions, decisions that involve high levels of uncertainty, trade offs of risk, or possible safety implications may include reviews and benchmarking or consultation with external stakeholders (government, regulators, etc.).

While the information and guidance below helps, it doesn't really tell one how to make a decision. The following information was taken from the UK Offshore Operator Association (UKOOA) Decision Process. Everyone wants to make "good decisions" Understanding decision-making processes and characteristics of good decisions will prove to be a valuable tool when making coating selections.

Table 2. Decision Making Process

Means of Calibration	Decision Content Type
Codes and Standard Best Practices Engineering Judgment Risk Based Analysis Verification Peer Review Benchmarking Company Values Internal Stakeholders Social Values External Stakeholder	====== Low ======== • Nothing unusual • Well understood risks • Established practice • No major stakeholder implications ===== Medium ======= • Life-cycle implications • Some risks tradeoffs/risk transfers • Some uncertainty or deviation from standard or best practice • Significant economic implications ====== High ========= • Very novel of challenging • Strong stakeholder view and perception • Significant risks tradeoffs/risk transfers • Large uncertainties • Perceived lowering of safety standards

Decision Making Process is illustrated below by the United Kingdom Offshore Operators Association (UKOOA) Decision Process

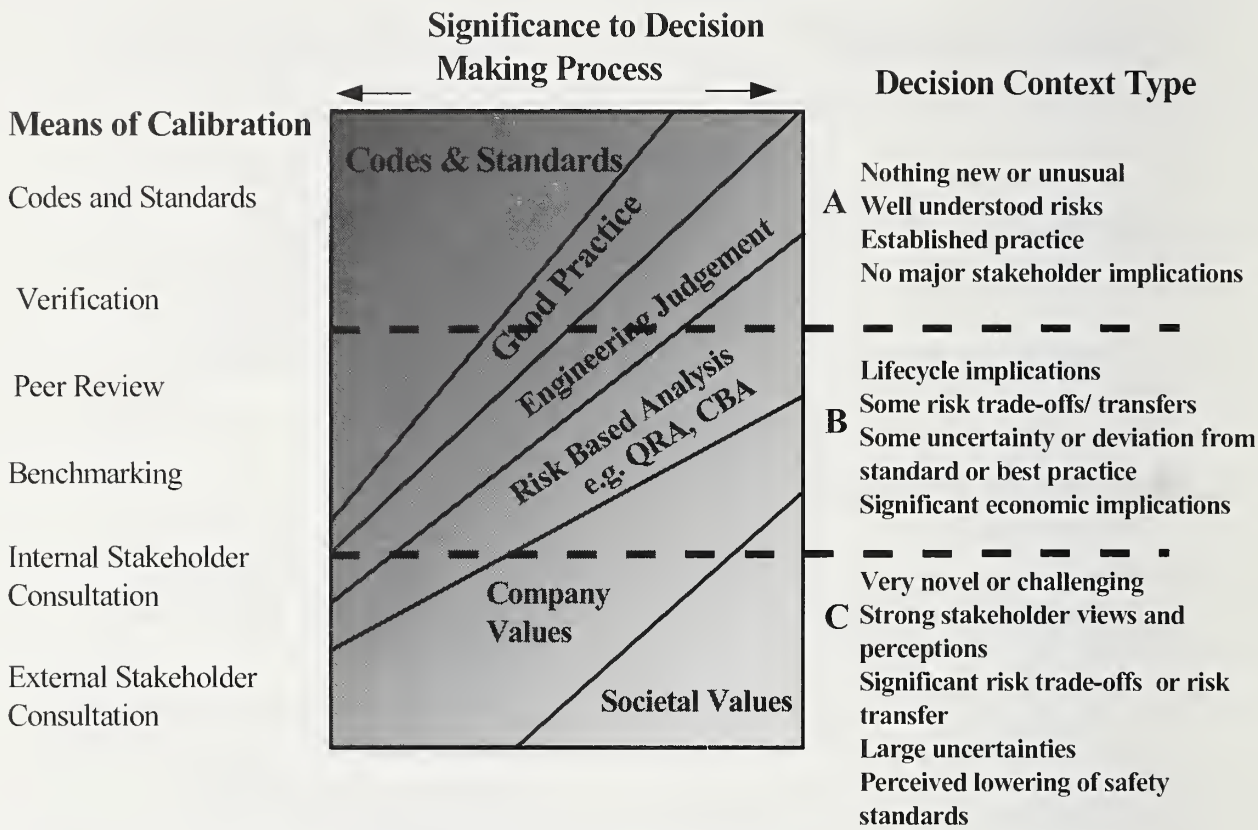

Figure 1. UKOOA Decision Process

Basic Decision Making Process

The Decision making process requires a consistent, transparent and well-defined process.

1. Study the problem and clearly define the objective(s)
2. Identify relevant criteria and define prerequisites (limiting prerequisites)
3. Extract (identify) all obligatory criteria
4. Creatively identify all available candidates that meet all prerequisites
5. Gather information on candidates and identify additional criteria
6. Assign weights to the obligatory criteria
7. Rank candidates
8. Take Action
9. Review Results (critical to effective corrosion control programs)

Good Decisions are the objective of every organization. Good decisions are:

- Made with an objective in mind
- Based as much as possible on relevant criteria and factual information about candidates (rather than subjective judgments),

- Flexible (subject to change based on better quality information or new criteria),
- Aligned with applicable laws, regulations and policies, and
- Made with informed consent of stakeholders

We mentioned criteria and candidates; what do these terms mean? Criteria are specific characteristics of the candidates, and candidates are possible solutions to the problem,

Criteria come in three flavors:

- Prerequisites (for candidate selection)
- Obligatory criteria (must have features)
- Desirable criteria (nice-to-have features)

Criteria receive weight in the ranking of candidates, which must meet obligatory criteria and prerequisites and which may exhibit other desirable characteristics

How does one weigh the criteria?

Weighing the Criteria can be performed in various ways. Two methods are:

(1) A distribution technique where 100 percent is distributed among the criteria and a (2) scaling technique where each criteria is assigned a number or points indicating preference (1 = low preference; normalize on total points, then multiplied by 100 to get percent). The Table below illustrates a method used by Shell Offshore in 1996. Qualitative words such as low, medium, high can be used to represent preferences.

How does one rank the candidates?

Ranking Candidates can be performed by using a Matrix method, which is the most common technique used by businesses for making decisions. Other methods abound such as: Pair wise Comparison; Pros & Cons; Pluses/Minuses/Implications (PMI) and Force Field Analysis. The point is to choose one and stick with it as long as it provides transparency and reliable rankings that prove out by experience.

Table 3. Coating Manufacturer Appraisal Summary Sheet (Shell/Estis, 1996)

Coating Manufacturer	A	B	C	D	E	TOTAL
1						
2						
3						
4						
5						
6						

Recommendation Levels should be established near 70 percent minimum for total weighted performance method

Ratings by: ______________________________-

A = Human Resources
B = Manufacturer
C = Technical Data
D = Practical Data (Experience)
E = Field Application

Note. Details concerning each of the above Criteria A through E were published for the 1996 New Orleans Offshore Corrosion Conference.

Changes That Could Apply Decision Making Process

There are numerous opportunities to apply the decision making process within a single-coatings project. Besides the basic process decisions such as the ones below may be evaluated.

Dry Abrasive versus Water Jetting (WJ) - WJ reduces dust, is faster, yet expensive, many different WJ systems with abrasive blasting capabilities are coming on market and are being captured by NACE and other standards.

Solvent to Solvent Free or Waterborne. Waterborne coatings have been around for some time, yet are not considered as a standard coating system. Solvent-free coatings have also been on the market for some time.

Plural Component Applications Such As Polyurethane, Polyurea Or Polyaspartics. Plural components (mixed at the gun) are an opportunity to apply highly resistant coating technology

Traditional Epoxy/Polyurethane to Polysiloxanes (3 coats vs. 2 coats). Polysiloxanes have a number of benefits (resilience and gloss retention) besides requiring only two coats

Use of Surface Tolerant Coatings. Surface tolerant coating systems are being used by the mature offshore maintenance industry. Two-coat systems are being utilized based on short-life cycle requirements (or maybe just to reduce expenses).

Single-Coat Zinc Versus Multicoated Systems. Single-coat zinc is well known to give long-life protection if properly applied and remains a good candidate coating because they are often used when the fabricator does not have time to apply multi-coat systems. Zinc has demonstrated a good record of accomplishment when properly applied. The good record of accomplishment in the Offshore Australia offshore and bridge maintenance industry has been documented (Alex S 1992).

Single-Coat Glass Filled Polyester Glass-Filled Polyester (GFP) is another coating system used in the offshore oil and gas industry (Corrosion 2004 #009, Tiong).

Conventional Vs. Airless. In the Gulf of Mexico maintenance programs (one-step trigger to two-step trigger gun spay mode) has long been an area that does not use airless possibly due to contractor driven practices.

Conventional Spray Coating to Metallizing. The use of Thermospray technology needs industry to make a greater effort to use and evaluate it with respect to life-cycle economics (Tiong, 2004).

Considerations in Coating Selection

Now that we know what makes a good decision; how to make one and have a list of potential opportunities some basic considerations and criteria for selection of coatings for offshore applications can be reviewed.

Prerequisites for Offshore Coatings

There are a number of prerequisites for selecting offshore coatings. Primary considerations include using the coating systems recommended by the supplier or the manufacturer for the appropriate application; ease of application provided by the supplier and the application contractor. Ensuring that the system used will

be maintainable over the required life of the facility. In addition, most important consideration is that the result will be a high performance/cost ratio over the life of the asset.

Coating Selection Criteria for Offshore Service

Obligatory Criteria

Obligatory criteria listed below are considered the major factors affecting coating performance

- Resistant to service environment
- Meets applicable regulatory requirements
- Compatible with substrate and surface preparation
- Compatible with available application techniques
- Compatible with cathodic protection

Desirable Criteria

Desirable Criteria listed below many be considered necessary to project success:

- Costs required to achieve effective protection
    - Low first cost
    - Low life-cycle cost
- Duration of effective protection
- Others

Suppliers and Manufacturers Input and Experience

Suppliers and coating manufactures are invaluable sources for coatings information. Although it must be understood that the information provided is not exhaustive. Previous experience and success can be much more important to evaluate. Short-term laboratory testing and on-site tests in accordance with ASTM D5064 or other specification will improve the end product should schedule and budget allow.

Ease of Application

The ability to apply coating with available equipment and level of operator experience can be important criterion. The level of inspection required to avoid excess/insufficient dry film thickness (DFT) at “hard to coat” areas, cavities, weld toes, re-entrant angles, and edges and curing and recoat time requirement

makes inspection another desirable criteria. Using new coating systems or application equipment will make the ease of application of the coating a key performance indicator. Special equipment will require special personnel or special training.

Maintainability

Coating system selection should include answering the questions," Who will perform the maintenance coating? Plant personnel? Contractors? How often is maintenance likely to be required? What is the tolerance of coating to installation damage? With longer life cycle performance maintenance coating and equipment integrity improves; however, when looking at the inspection, repair and maintenance record of accomplishment it has been found that the condition projects are delivered in are the root cause of coating and corrosion related equipment failure.

Maintenance coating must be addressed much like other preventative-maintenance practices. There must be a commitment schedule and a clear application scope. One needs to have a commitment from financial and human resources to do the work. The work must be manageable addressing zones of failure rather than isolated spots. The program that puts together a good paint crew and keeps it working reduces the dollar per square foot cost and results in a longer performing corrosion barrier. Many offshore operators have learned that keeping one or more good paint crews working all year round produces the most efficient results.

Cost

When looking at the cost of a coating system, one must consider performance. Comparisons must be normalized on an equal basis. Generic type of coating, solids content and various other properties must be compared. Again, cost is less important than performance in most instances.

Service Environment

All the various service environments and any future changes must be considered. These variables include:

- Temperature extremes and thermal cycling
- Relative humidity

- Immersion, wet/dry cycling, or dry
- Redox potential of environment
- pH extremes
- Potential for solvent, chemical, cargo or operations exposure
- Potential for UV exposure
- Potential for mechanical impact/abrasion damage
- Marine organisms

Regulatory Requirements

Regulatory requirements include the amount of volatile organic compounds (VOCs) that may be emitted to the atmosphere during application and curing are becoming more and more restricted. Regulations may vary by locality. Low-VOC coatings are becoming more available, but they are generally less effective than older high-VOC formulations, and selectors must consider the performance differences when making the final selection or recommendations. Hazardous Air Pollutants (HAPs) regulations is also a consideration.

Substrate Compatibility

Coating selections for new construction and maintenance painting must be compatible with the substrate over which they will be applied. Will new coating be applied over existing coating or bare metal? Will the substrate be new steel, rusted steel, and/or pitted steel?

What level of surface preparation can be achieved reliably with respect to the condition of the substrate and the recommended primer coating? Climate conditions must to noted (temperature, relative humidity, wind). With today's computer databases, this type of information may be much better predicted. The degree of tolerance of coating to surface preparation irregularities is also considered.

Application Alternatives

Application including access requirements and surface preparation represents the majority of installed costs for most coating systems. The Selector should consider all feasible access scenarios and abrasive blasting practices evaluating applications alternatives, including brush, roller, and various spray applications. Final coating selection may depend more on regulatory requirements, control of overspray, etc. than on technical performance factors. Tough application

requirements around edges, fasteners, flange connections, welds require major consideration and attention.

Cathodic Protection

Combining Cathodic Protection (CP) with a protective coating is generally believed to be the best method for protecting submerged structures. Sykes, at the 1999 New Orleans Offshore Corrosion Conference demonstrated that the corrosion rate of an unprotected insulated twelve-inch tubular member exhibited 14 mils per year (mpy) corrosion rate versus less than two mpy for a member attached to the offshore structure and cathodically protected.

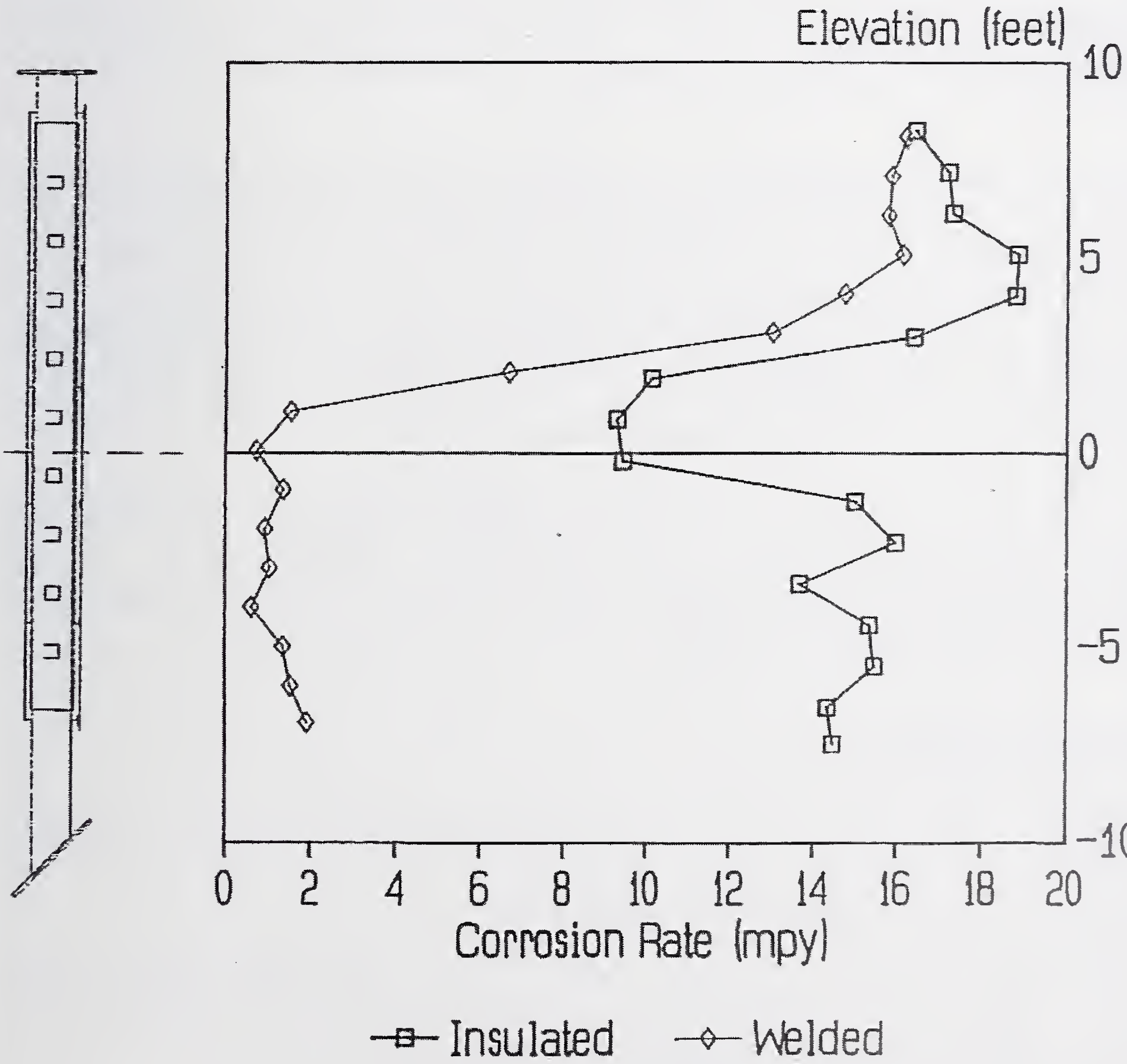

Figure 2. Corrosion rate as a function of elevation of 12 inch tubular members electrically coupled to offshore platform structure.

CP system design and coating selection must be compatible if the structure is to reach and possibly exceed its design life. Compatibility can be achieved through effective communications between coating selectors and CP system designers. Robust CP system designs can offset less than optimal coating selections and vice-versa. However, too robust a CP system may cause cathodic disbondment and other problems with an otherwise suitable coating system. Thick coatings for thermal insulation may hinder (shield) effective CP of critical surfaces.

Costs of Protection

The cost of effective corrosion protection by protective coatings can come from a number of cost drivers. Cost of materials (paint and abrasives); labor costs for surface preparation and application, equipment and access costs (scaffolding, rigging) are the major items. Transportation (mob/demob) costs in an offshore environment can also be a high-ticket item.

Downtime costs due to weather or operational and construction activity conflicts; although, out of the control of the coating profession can be reduced by good practices utilizing downtime to perform the many other necessary work tasks such as equipment maintenance, housekeeping, and training activities. Other costs due to regulatory compliance, overhead costs for project management, inspection and cost estimation are required to provide a high performance coating system. Cost for providing special conditions for curing and recoat time for some coatings can added to the final coating cost.

The chart below attempts to illustrate the potential cost of a low-performance coating project as a function of a high-performance coating project. A much higher overall cost occurs because more maintenance coating and equipment repair and replacement costs result.

Duration of Protection

The length of time that a properly selected and applied coating will provide protection from significant corrosion depends on the rate of degradation of the coating in the particular service environment. Subjective evaluations of degradation rate are suitable for small projects or projects with low risk, i.e., low consequences of failure. However, when projects with higher levels of risk require a more objective approach such as that provided by a combination of laboratory and field-testing is needed costs may be higher.

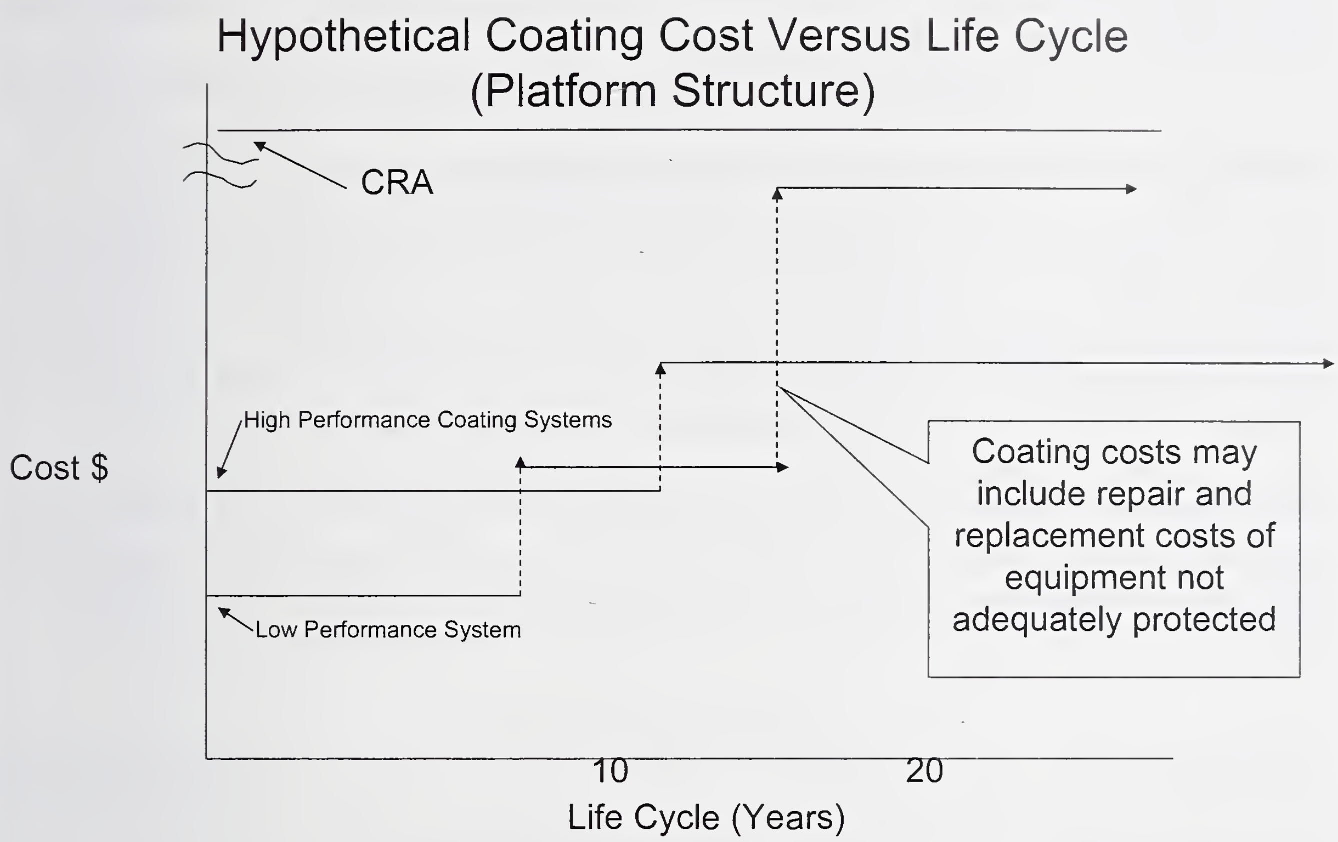

Figure 3: Hypothetical coating cost as a function of life cycle.

Coating Selection and the Fast-Track Projects

Many of today's fast-track projects do not include corrosion engineers or coating specialists on the design team. This inefficiency results in coating-selection decisions being made largely by non-specialists on the basis of cost and what is most expedient (poor decisions). Compressed project schedules and tight budgets result in less time and money for essential coating activities. These issues result in a loss of the best opportunity to coat a structure properly, and receive less than maximum benefit from coatings, which may affect future evaluations of coating performance.

Overcoming the Difficulties

In order to overcome the difficulties of applying a high-performance coating system, one must recognize and demonstrate to management the importance of coating selection to project performance (Opex). Management must resolve to make better use of existing coatings expertise within their organizations. An

improved transparency of process communicating between all levels of the organization needs to occur.

Model for Improved Utilization of Protective Coatings

Like any other part of a construction or maintenance project, coatings-application projects must be managed not only within a Materials and Corrosion Management Program, but also within the entire Organization. With today's many reorganizations, we have seen not only the reduction of manpower but reduced overall awareness and understanding of the coating process.

Regrettably, it is only when we see catastrophic failures such as recent DOT pipeline failures that attention is paid to the root causes of the failure. The failure might have just been a coating professional allowing a "holiday" in the coating.

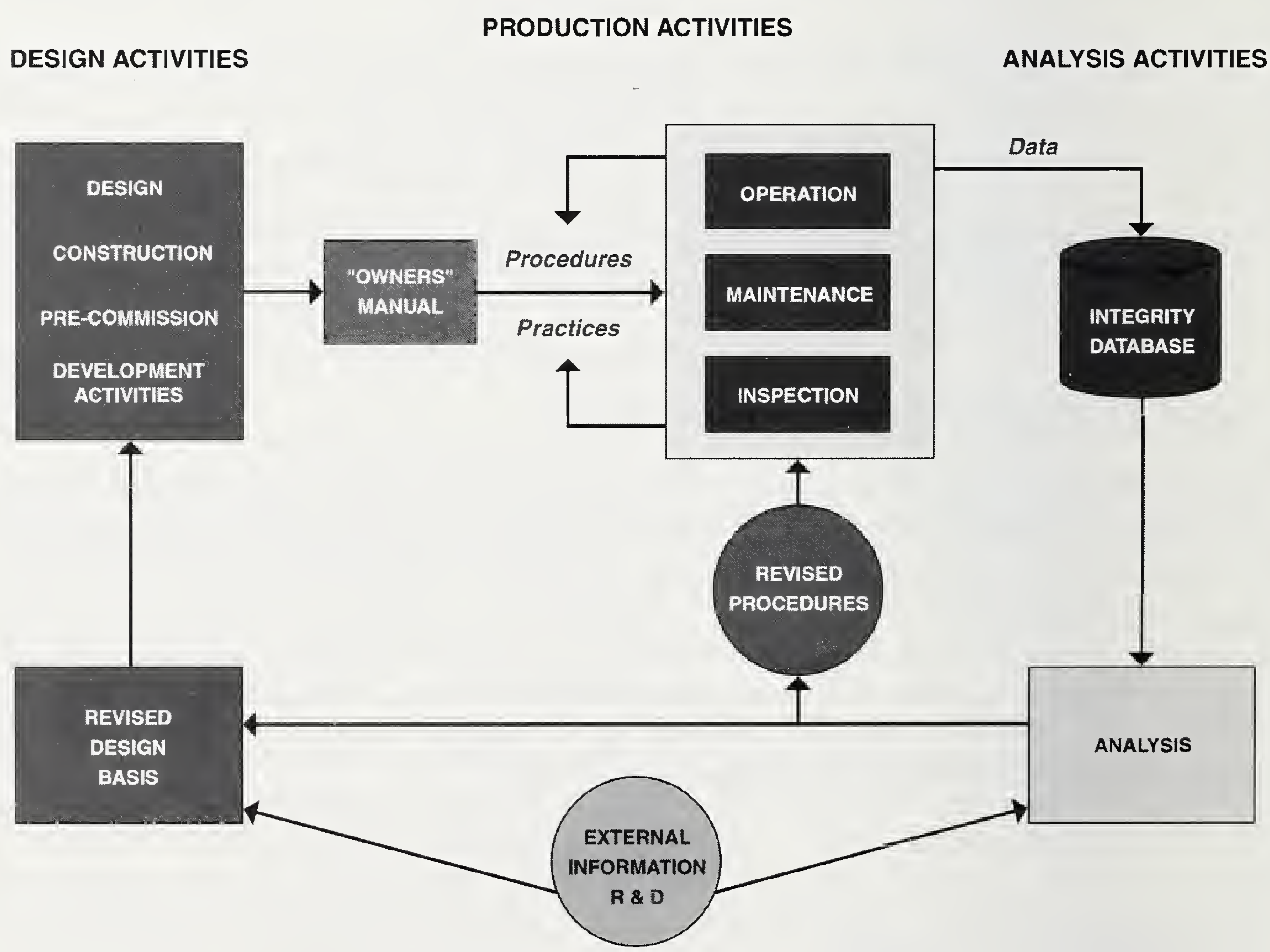

Figure 4: Model for improved utilization of protection coatings.

Conclusions

Coating selection for offshore service is important and difficult.

1. The coating selection process can be improved by applying classical decision-making theory to the problem.
2. Level of complexity required in making the decision depends upon context and level of risk.
3. Whatever decision making process for coating selection is chosen by an organization, it should be well documented and transparent; and it should deliver practical, cost-effective solutions.
4. Coating selections should be made by experienced individuals whenever possible, and the selections should reflect proper balance of technical and economic factors.
5. The root cause of many coating failures i.e. premature coating breakdown comes from allowing outside forces to compromise the coating application process.

Although there are many components to implementing and maintaining a successful coating program, one needs to remember that these key components of a coating system are based on actual service environments, surface preparation requirements and coating application options. Finally, one should always remember to follow the Health, Safety and Environmental management programs within various organizations involved with producing a high performance coating system.

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Corrosion Protection for Offshore Pipelines

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Abstract

Offshore pipelines frequently have an expected service life in excess of thirty years. To survive sub-sea, offshore pipelines are protected from corrosion with protective coatings and cathodic protection. Coatings must be tough, have good adhesion to the pipe, resist mechanical damage during installation, easily repaired, easily coated in the weld lanes, and be compatible with cathodic protection. Cathodic protection is provided by sacrificial bracelet anode systems or impressed current cathodic protection systems (ICCP).

Many different types of coatings are used for offshore pipeline applications. These include fusion bond epoxy (FBE), dual and multilayer FBE, three-layer FBE Polyolefin, polyolefin, and coal tar enamel coatings [1][2][3]. In addition to protective coatings, sub-sea pipelines are often coated with cement-weight coatings to provide negative buoyancy.

Internal corrosion control methods are dependent upon service conditions. For gas pipelines internal corrosion controls includes lowering the dew point of the gas and use of inhibitors. For oil pipelines, reducing the water cut, corrosion and scale inhibition, and biological controls are used to mitigate internal corrosion. For both gas and oil pipelines internal corrosion coupons are used to monitor the effectiveness of the corrosion controls. Erosion corrosion can be controlled by removing solids from the stream and by mechanical design. Droplet corrosion in gas streams are controlled by decreasing the dew point of the gas to a temperature below the lowest expected temperature of the pipeline. To minimize erosion sand removal from the production stream in an important part of the corrosion control design.

Corrosion allowance for internal corrosion is frequently used to provide additional metal for corrosion loss. Corrosion and scale Inhibitors as well as biocides cannot be relied upon to be more than 90 percent effective; therefore, to allow for small amounts of corrosion, addition metal is added to the pipe wall thickness. The corrosion allowance should anticipate the maximum metal loss over the life of the pipeline.

Introduction

During the design of an offshore pipeline many corrosion mitigations methods are considered. Coatings on the outside of a pipeline provide the first level of protection against corrosion by seawater. Because no coating is perfect, cathodic protection (CP) provides addition corrosion protection where holidays or coating damage may exist.

Internal corrosion can lead to changes in the material selection used for pipeline design. Overly aggressive internal corrosion may require the use of corrosion and scale inhibitors, biocides, corrosion allowances and internal linings. Without special treatment some internal corrosion is best handled in corrosion resistant alloys such as 13 Cr stainless steel or duplex stainless steel.

These decisions are all considered during the design of an offshore pipeline. Figure 1 shows a flow diagram for a corrosion integrity management plan for design and operation of an offshore pipeline. The corrosion potential of the process fluids is of prime importance. The temperature and pressure of the fluids have a strong influence on the choice of coating materials and current requirements for the cathodic protection design. Operating temperatures of $65^{\circ}C$ to $100^{\circ}C$ ($150^{\circ}F$ to $212^{\circ}F$) or higher are common. Because the rate of corrosion is influenced by the temperature of the fluid, as the fluid temperature increases every $10^{\circ}C$ ($18^{\circ}F$) the corrosion activity will nearly double.

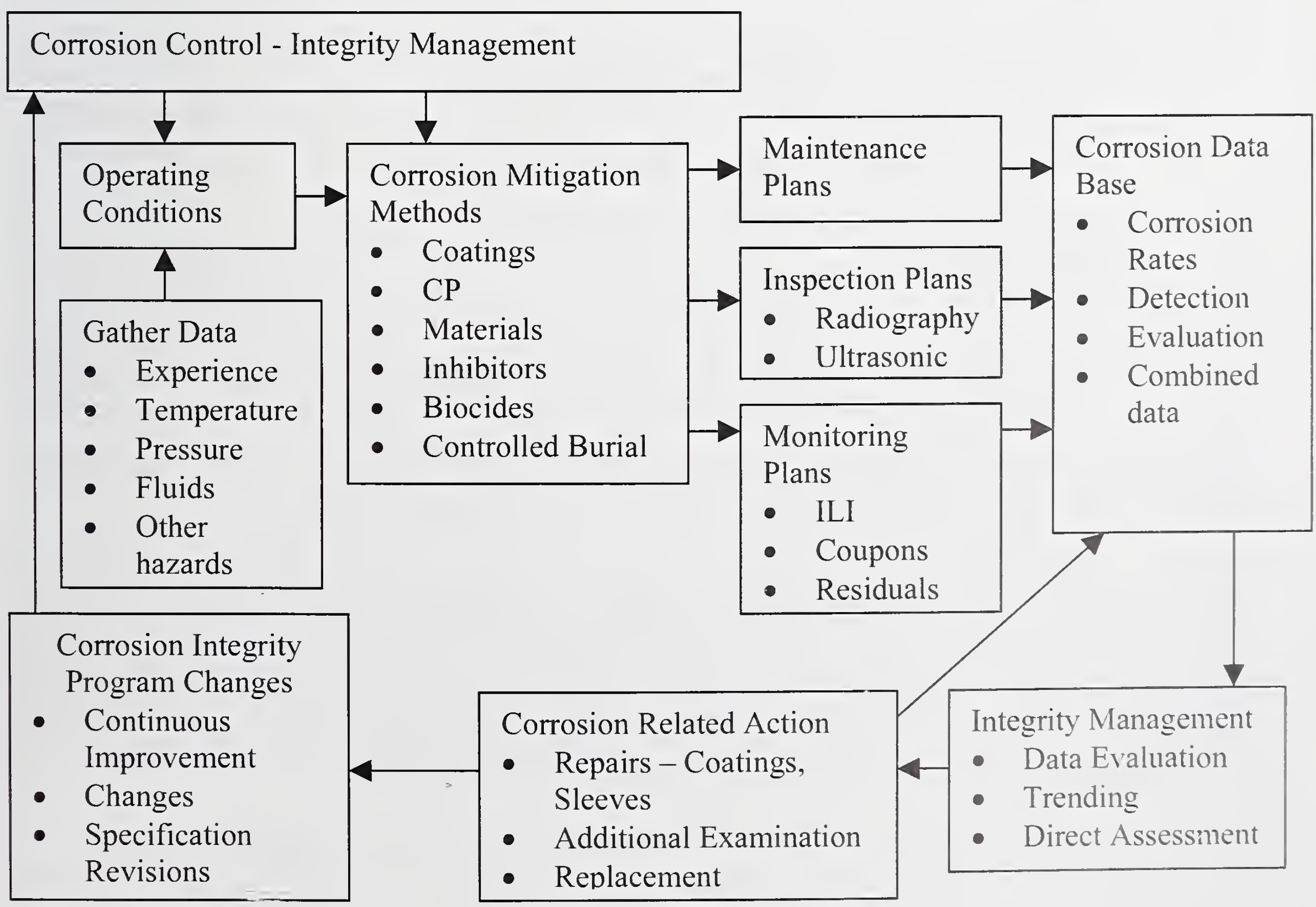

Figure 1. Development of a corrosion integrity management plan

Fusion Bond Epoxies FBE

FBE has been used since the early 60's.
Dual layers – FBE with an FBE friction surface

Internal Corrosion

The final design for corrosion control not only includes material selection, coatings, and cathodic protection, but also includes monitoring plans, inspection plans, and maintenance plans.

Evaluation of Corrosion Potential in Hydrocarbon Systems

International standards give guidance in evaluation of the expected level of corrosion. NORSOK Standard such as M-001 Material selection [4], M-503 Cathodic Protection [5], and M-506 CO2 Corrosion Rate Calculation Model [6] give some guidance in calculating corrosion potential. Evaluation of the corrosion potential should include at a minimum:

- CO2-content.
- H2S-content.
- Oxygen content and content of other oxidizing agents.
- Operating temperature and pressure.
- Organic acids, pH.
- Halide and metal ion concentrations
- Velocity, flow regime and sand production.
- Biological activity
- Condensing conditions.

A gas is considered dry when the water dew point at the actual (operating) pressure is at least 10°C (18°F) lower than the actual minimum operation temperature for the system. Of these corrosion considerations, only temperature and pressure effect the selection of external corrosion controls.

Typically for pipelines, an inhibitor efficiency approaching 90 percent can be achieved. The inhibitor efficiency should include the effects of glycol and/or methanol injection. The anticipated corrosion rate can calculated using standards like the NORSOK standard M-506 CO2 Corrosion Rate Calculation Model [6]. Unless field experience or test data are available, the corrosion rate in an inhibited hydrocarbon should be verified by corrosion tests.

Pipeline Failure Modes

Offshore pipelines have several potential failure modes or threats. These treats to an offshore pipeline include external and internal corrosion. For offshore pipelines the main external corrosion failure modes are:

- Seawater corrosion, scowering, abrasion of the coating, and sea bottom movement
- Galvanic corrosion (dissimilar metals in an electrolyte)
- Oxygen concentrations cell corrosion (pitting and crevice corrosion)

Offshore pipelines main internal corrosion failure modes are:

- Acid gasses and organic acids combined with water
- Erosion, and erosion corrosion caused by sand and entrained particles (or droplets)
- Scaling cause by incompatible fluids
- Microbiologically Induced Corrosion (MIC), accelerated corrosion caused by or as a result of microbiological activity.

Coating and Coating Selection

The most common coatings used today for offshore pipelines are fusion bonded epoxy (FBE) coatings, dual layer or multiple layer FBE, three layer FBE/polyolefin adhesive/polyolefin, and coal tar enamel coating. Typically for offshore pipelines these coatings are normally shop applied.

Common requirements for shop-applied fusion bonded epoxy coatings can be found in RP0394-2002 Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating [7] and CSA Standard Z662-03, Oil and Gas Pipeline Systems [3] and are shown in Table 1. FBE coatings have been used for pipeline coatings since the early 1960's.

Modified fusion bonded epoxy coatings used offshore include dual powder coatings or multiple layer FBE coating. Dual powered coatings are used improve the gouge resistance and toughness of FBE during direction boring [9]. A rough coat is frequently used to improve friction between the FBE and a cement weight coating. Rough coats also improve traction for lay barge operations and improve safety [1]. Thicker dual powder coatings can also enhance high temperature performance. Dual powder coating system can be used at operating temperatures of 110°C (230°F) or higher.

Three layers FBE/polyolefin adhesive/polyolefin have also been used offshore since the early 1970. The polyolefin to coat can be either polyethylene or

polypropylene. Special multilayer systems are available. These systems include systems with high glass transition temperatures (T_g) FBE and modified polypropylene for high temperature operation, increased polyolefin thickness for directional drilling, and additional layers for pipeline insulation (polypropylene foam).

A polyolefin rough coat or rough-finish consisting of polyolefin powder applied during shop application has also been used to improve the friction between the polyolefin outer coating and the cement weight coating. Densely filled polypropylene has been used to replace concrete weight coating.

Table 1. Qualification requirements for fusion bonded epoxy coatings

Test	Acceptance Criteria
Cathodic Disbondment (24 hours)	Maximum average radius: 6.0-mm (0.25 inches)
Cathodic Disbondment (28 days)	Maximum average radius: 8.0-mm (0.3 inches)
Cross-Section Porosity	Rating or 1 to 4
Interface Porosity	Rating of 1 to 4
Flexibility (3°/Pipe Diameter at 0° C[32° F] or -30° C [122° F])	No cracks, tears, or delamination
Impact Resistance	1.5 J (13 inch-pounds) minimum
Hot-Water Soak	Rating of 1 to 3

Other coatings used offshore include extruded polyolefin coatings are similar to those described in RP0185-96 Extruded Polyolefin Resin Coating Systems with Soft Adhesives for Underground or Submerged Pipe [8] have also been used for offshore pipelines since the early 1960's. A typical application procedure coal tar enamel pipe coating systems can be found in RP0399-99 Plant-Applied, External Coal Tar Enamel Pipe Coating Systems: Application, Performance, and Quality Control [9].

Typical extruded polyolefin coatings properties are given in Table 2. Extruded polyolefin coatings have good resistance to moisture absorption and high dielectric strength.

Coal tar enamels have been used as a pipeline coating since the 1930's. Typical coating properties for coal tar enamels are given in Table 3. Coal tar enamel coating have good resistance to moisture absorption, are easy to apply to the girth weld zone, and a good coefficient of friction.

Table 2. Typical properties for extruded polyolefin coatings

Property	Typical value Polyolefin Resin	Butyl Adhesive
Density	Minimum 0.95 g/cm^3	Minimum 1.00 g/cm^3
Flow Rate	Maximum 0.75 g/10 minutes	Maximum 8.00 g/10 minutes
Tensile Elongation	500%	
Tensile Strength	Minimum 19 MPa (2,800 psi)	
Hardness	60 (Shore D)	
Dielectric Strength	>28 V/μm (700 V/mil) for the total system	
Water Absorption	Maximum of 0.02% for the total system	

Table 3. Typical properties for coal tar enamel coatings

Property	Typical value
Thermal Conductivity	0.16 W/m-K (1.1 BTU/ft2/h/°F/inch)
Electrical Resistance	1×10^{14} ohm-cm
Dielectric Strength	>10 V/μm (250 V/mil)
Water Absorption	2% or 0.3 g/30 cm^2 (0.1 oz/50 in^2)
Water Vapor Permeability	6.5×10^3 perms
Cathodic Disbondment (60 days)	Maximum radius of 8-mm (0.3 in.)
Adhesion	2.4 MPa (350 psi)
Coefficient of Friction	0.59 to 0.91

Other Design Considerations

Most offshore pipelines are designed to allow pigs for cleaning and In-line inspection (ILI) using intelligent pigs.

Today most offshore pipelines are designed to allow for the passage of cleaning pigs to remove water, sediments, wax, and other debris, and in-line inspection (ILI) by instrumented smart pig. To facilitate pigging offshore pipelines designed to be piggable have large radius bends, usually at least 5D. In addition to allowing pigs to pass, large radius bends also helps reduce erosion.

“Deadlegs” and low flow or intermittent flow piping often results from pig launching and receiving designs. These areas can be subject to accelerated corrosion because of the stagnant conditions, accumulation of water, debris, and

microbiological activity. Ultrasonic examination for metal loss in these areas becomes very important.

Another common design corrosion consideration is to provide additional metal for internal corrosion allowance. Common corrosion allowances are shown in Table 4.

Table 4. Typical corrosion allowances for internal corrosion of carbon steel subject to in service corrosion.

Service condition	Corrosion Allowance
Inter-field oil lines	3-mm (0.125") plus inhibition
Inter-field gas lines	1.5-mm (0.063") dry or 3-mm (0.125") wet plus inhibition (may require CRA)
Stabilized or process crude lines	2-mm (0.078") plus inhibition
Dried gas lines	1.5-mm (0.063") dry

Cathodic Protection Design

Cathodic protection is applied to protect holiday in the coating. Cathodic protection is accomplished by either sacrificial anodes or impressed current cathodic protection systems (ICCP). Typically aluminum bracelet anodes are used for sacrificial cathodic protection systems. The most common aluminum alloy used for bracelets anodes is Aluminum-zinc-indium.

Design of cathodic protections system for offshore structures should be done in accordance with RP0176-2003 Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production [7] or RP0169-2002 Control of External Corrosion on Underground or Submerged Metallic Piping Systems [8]. Table 5 shows some typical values used in cathodic protection design. To design cathodic protection systems information on the total current requirement, resistance, expected life, and anode current out are needed.

Table 5. Cathodic protection design parameters and coatings design considerations

Design parameter	Typical Value
Seawater Resistivity	20 – 25 ohm-cm
Saline Mud	100 – 150 ohm-cm
Anode open circuit potential - buried	-1.05 V (Ag/AgCl)
Anode open circuit potential - seawater	-0.95 V (Ag/AgCl)
Anode Consumption	1280 A hours/ pound
Anode Utilization Factor	0.80
Coating Breakdown Factor (FBE)	0.5% to 1.0% (initial) 10% (after 30 years)
Insulation Breakdown Factor	0.5% to 1.0% (initial) 3% (after 30 years)
Neoprene Breakdown factor	0.5% to 1.0% (initial) 5% (after 30 years)
Design current density for bare steel in seawater	12mA/ft^2 (initial) 7mA/ft^2 (after polarization)
Design current density in sand or mud	2mA/ft^2 (initial and after polarization)

Normally sacrificial cathodic protection systems for pipelines consist of bracelet anode spaced periodically along the pipeline. For design of a sacrificial cathodic protection system, the current demand is calculated from the coating breakdown factor, design current density, and the total surface of the pipeline as shown in equation 1.

$$I_{Req} = I_{design} * A_{pipe} * F_{Coating} / 1000 \qquad (1)$$

where: I_{Req} is the total current demand

I_{design} is the design current density

A_{pipe} is the total area of the pipeline

$F_{Coating}$ is the coating breakdown factor

The total anode weight required is then:

$$W_{anodes} = (I_{req} * 8760 \text{ hr/year} * \text{expected life}) / (\text{Consumption rate} * \text{efficiency}) \qquad (2)$$

where:

W_{anodes} is the total anode weight need to provide the current requirement

I_{req} is the required current calculated in equation (1).

The number of anodes then is calculated as:

$$N_{total} = W_{anodes} / W_{bracelet} \qquad (3)$$

where:

N_{total} is the total number of bracelet anodes requires

W_{anodes} is the total weight calculated in equation (2).

$W_{bracelet}$ is the weight of each individual bracelet anode

Bracelet anodes are normally attached at girth welds between pipe joints by welding anode tabs to the pipe. Once the number of anodes required is calculated the spacing between anodes can be calculated. Normally the number of anodes is rounded up to accommodate the spacing between girth welds. In addition to the current requirements anode resistance and anode out put need to be considered and may result in the need for additional anode or a change in anode design.

Impressed current cathodic protection systems are used if the pipeline is relatively short, up to ten miles. The impressed current can be provided on shore and/or at the operating platform. Current demand is calculated similar to the sacrificial current demand. ICCP has the added advantage of being able to change the current output. During initial startup of the CP system a higher current can be supplied to increase the rate of polarization. As the pipeline polarizes the current can be adjusted to reduce to current out put and maintain protective potentials on the pipeline.

Sacrificial cathodic protection system sometimes try to make this adjustment by provide small magnesium anodes which are quickly consumed but provide a temporary increase in the current output.

Monitoring and Inspection

As part of the corrosion designs for offshore pipelines corrosion monitoring and corrosion inspection plans are needed. These plans are intended to monitor the

effectiveness of corrosion mitigation and to measure corrosion as the pipeline ages.

Monitoring

Monitoring consists for corrosion probes, coupons, and instrumentation. Normally resistance probes are used to measure the apparent corrosion rate. This data can be continuously monitored for day-to-day corrosion control. Coupons are used to measure corrosion rates. Coupons are installed for a set time period. After exposure, the coupon is extracted, usually under full pressure, the coupon examined and weighed. This data is frequently used to determine the effectiveness of the inhibition and biocide used to control corrosion.

Other monitoring frequently used to evaluate offshore pipelines includes side-scanning sonar to detect areas where the pipeline may be bridging the ocean floor or where currents have cause the ocean floor to shift. As necessary the pipeline addition support or sand bags can be added to protect the pipeline.

Cathodic protection monitoring is very important to an offshore pipeline. Cathodic protection monitoring should include a potential survey and current drain surveys. These surveys provide information about the condition of the cathodic protection system, as well as, information about the coating performance and the coating breakdown.

Inspection

Non-destructive examination methods such as radiography, ultrasonic survey, acoustic emission or other similar technique are frequently used to measure the remaining pipeline wall thickness. Where accessible the remaining wall thickness can be directly measured by ultrasonic surveys or radiographic surveys.

In-line inspection (ILI) tools or smart pigs often use ultrasonic techniques or magnetic flux leakage to measure remaining wall thickness. In addition, smart pigs can identify dents, settlement, cracks, corrosion at welds, and other pipeline anomalies. Both internal and external corrosion can be measured using smart pigs.

Corrosion Database

A substantial amount of inspection and monitoring data will be collected over the pipeline's life. Examples of such data are cathodic protection (CP) surveys, intelligent pigging results, pipeline coating inspections, span length, corrosion probe & coupon data, visual, NDT inspection results and corrosion map data.

Other examples include details of inhibition programs and levels of conformance to plan, locations and technical operational information on CI systems, comparison of actual wall thickness with design wall thickness of pipelines, piping and vessels, conditions of external coatings and internal linings. These data may reside within various departments and considerable effort may be needed to collect, collate and arrange this data in a format that will allow ready comparison against acceptable values.

Monitoring and inspection over the life of the pipeline will generate a great number of data points. Today most pipelines use an electronic database to store the pipeline inspection, monitoring data and integrity data. Electronic databases greatly simplify the comparison of measured values against design values during asset integrity assessments. Identification of trends in coating integrity, cathodic protection, and internal corrosion can be correlated with asset degradation.

Conclusions about Coatings for Offshore Pipelines

The first line of defense for an offshore pipeline is the coating on the pipe. Many different types of coating are used for offshore pipeline. Cathodic protection is used to protect holidays in the coating. Coatings for offshore must have good resistance to water absorption, cathodic disbondment, and strong adhesion to the pipe.

Testing of coatings can provide some guidance concerning the ability of a coating to survive the offshore environment. Coating history and performance is very valuable information.

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Experience with Coating for Corrosion Protection from the Norwegian Continental Shelf

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Abstract

This article will aim at highlighting various phases of Norwegian offshore field developments, from integrated fixed jackets and GBS' to floating production units, e.g. FPS0's, semi-submersibles, where the coating design, application and maintenance must be such that the facilities sustain the harsh environment and weather conditions encountered offshore Norway. Also, as a regulator, the article emphasizes on aspects of the regulatory regime e.g. experiences with prescriptive and functional requirements, improvements achieved in protective equipment for surface treatment, development of regulations for coatings and coatings application and operational experience with various coating systems.

The Petroleum Safety Authority Norway

The Petroleum Safety Authority Norway (PSA) was established 1 January 2004, as an independent governmental supervisory authority which reports to the Ministry of Labour and Governmental Administration. It is located in Stavanger, on the southwest coast of Norway and shares offices with the Norwegian Petroleum Directorate (NPD). PSA employs approximately 150 persons.

PSA has responsibility for safety, emergency preparedness and working environment in the petroleum activities. Upon establishment, enforcing regulations relating to health, safety and working environment (HSE) in the petroleum activities is a responsibility of PSA. Also, the areas of authority have been extended and incorporate supervisory activity towards health, emergency

preparedness and working environment at onshore petroleum process facilities and onshore transportation pipelines.

Leading principles for PSA are to provide information and counselling towards the petroleum industry, cooperate with corresponding HSE authorities both nationally and internationally and promote transfer of experience and knowledge of health, safety and working environment in the society in general. With such principles in mind, our ambition with this article is to contribute with experience on development of protective equipment for operators, address operational coatings experience and development of regulations.

Norwegian Oil and Gas Fields

As of January 2004, 44 oil and gas fields are in production on the Norwegian Continental Shelf (NCS). These are located in the southern North Sea sector (12 fields), the northern North Sea sector (27 fields) and the Norwegian Sea (five fields). Seven fields are at the moment under development. A total of 112 platforms are installed, 94 fixed installations and 18 floating production and storage installations.

The North Sea

Ekofisk, an oil field located in the southern North Sea, was discovered in 1969 and put in production in 1971. Developments of offshore facilities at Ekofisk make it serve as a hub for oil and gas pipelines to the UK and the European continent. Although Ekofisk has been in production for more than thirty years, the reservoir still contains oil and gas for several decades of production.

Frigg, a gas field located in the northern North Sea at the borderline of Norway and UK, was discovered in 1971. The first gas was piped to St. Fergus in Scotland in 1976. Frigg is planned to cease production in 2004. Statfjord, yet another oil field in the northern North Sea was put in production in 1979. Statfjord, along with other fields in the Tampen area, e.g. Gullfaks, Snorre and several minor fields, were the most important oil producing province on the Norwegian Continental Shelf in the 1980's and 1990's.

With the Troll development, Norway moved on to take advantage of its great gas resources and marks a development where gas export has a significant importance in terms of overall petroleum production. Also, Troll is a major contributor to Norway's oil production. The oil in the reservoir is trapped in a zone so thin that the oil has to be produced through some of the worlds longest horizontally drilled wells.

The Norwegian Sea

Development of oil and gas fields in the Norwegian Sea started with Draugen, an oil field, which was put in production in 1993. Until present, five more developments have been completed, where Asgard ranks as one of the largest subsea developments worldwide.

The Barents Sea

In the Barents Sea, the development of Snohvit is ongoing. This development includes offshore subsea facilities and an onshore Liquefied Natural Gas (LNG) plant. Snohvit is due for production in 2006.

Offshore Infrastructure Investments

In the past three decades since the production of oil on the Norwegian Continental Shelf began in 1971, the total investment in offshore structures has exceeded 660 billion Norwegian kroner ($94 billion US). It has been estimated that the cost of procurement and application of all coatings accounts for 1.5 to 3 percent of the total cost of fabricating a platform topside. The cost of procurement and application of coatings are then in the range of 10 - 23 billion Norwegian kroner ($1.4 - 3.3 billion US).

Although Norwegian offshore installations have a coating design and coatings application in accordance with established standards and procedures, we have in recent years seen examples of deterioration and degradation of coatings on installations after just a few years of operation. Concerns with safety aspects like corrosion, leaks, etc. are reasons for the authorities emphasis on applying qualified coating products, operators, supervisors and procedures.

Norwegian Oil and Gas Production

In 2002, an average production of 3.33 million barrels of crude oil each day ranks Norway as seventh among the oil producing nations. With an oil export of 3.12 million barrels each day, Norway ranks as the third largest oil exporter worldwide. Oil is shipped to the market through pipelines and by offshore offloading to crude tankers.

Norway is a major supplier of gas to the European market. Norwegian supplies cover 11 percent of the European demand for gas. In 2002 the export amounted to 64.2 billion Sm^3 dry gas. The export covers two percent of the consumption on a worldwide basis.

The gas is transported to the UK and the European continent through a pipeline grid of more than 6000 kilometres, which makes this the longest offshore transportation grid.

Production Forecast - Prosperity or Decline?

Norwegian oil production has been at a plateau since 1996 and estimates indicate a production rate of slightly less than three million barrels each day until 2005. From then on, the oil production will probably decrease.

Two scenarios for oil and gas production from the NCS may be foreseen; *the decline scenario* and *the long-term scenario*. The first, *decline*, assumes a consensus among the petroleum industry and the authorities that what has been achieved so far is satisfactory. It involves stagnation for the NCS and of the Norwegian oil and gas industry over the coming ten to twenty years. The alternative, more prosperous *long-term scenario*, suggests a common effort from the petroleum industry and the authorities to extract the petroleum resources in a cost effective manner. The government's aim is that the long-term scenario will prevail and the Parliament (Stoning) has concurred with this objective, which puts oil and gas production on the NCS in a century-long perspective.

Norway's oil and gas resources belong to the Norwegian community and must be managed for the maximum benefit of present and future generations. An overall objective of government oil and gas policy is accordingly to ensure that the largest possible share of value creation from petroleum operations accrues to the community.

Development of Regulations and Standards for Coatings and Coatings Application

The *Regulations concerning loadbearing structures in the petroleum activities of February 1992*, with five guidelines, gave prescriptive requirements on the regulation level. The guideline *Guidelines of corrosion protection of loadbearing structures* provided examples to how these requirements could be met.

The guidelines dealt with issues like pretreatment, cleaning, paint work including control during application, film thickness, adhesion, production and test reporting and referred to applicable national and international standards.

As part of a drive to reduce costs related to the development of Norwegian offshore oil fields, the Norwegian government established the NORSOK (The competitive standing of the Norwegian offshore sector) project in 1993, which implied involvement of oil companies, suppliers and the authorities to standardize technical specifications for offshore projects.

NORSOK Standard M-501 Surface Preparation and Protective Coating

Prior to the NORSOK project, during 1991, the coating industry decided to produce a standardized coating specification, which would improve the quality of work performed in the coatings industry. The specification would make it easier for industry personnel to have one set of standards, methods and requirements. The first revision of the standardized coating specification was made during 1991 and 1992. The standardized coating specification has been used as a basis for the NORSOK coating specification entitled *M-501 Surface Preparation and Protective Coatings.*

The authorities supported the project and made reference to the standard when issuing updates of the regulations. In the *Regulations Relating to Loadbearing Structures* of February 1998, the guidelines on corrosion protection for the most had been replaced by a reference to *NORSOK Standard M-501* as a recognized standard.

Furthermore, NPD (now PSA) in 2002 issued jointly with Norwegian Pollution Control Authority and Norwegian Social and Health Directorate, a revised compilation of regulations comprising the original 14 prescriptive regulations to five functional regulations with additional guidelines, entitled *Regulations Relating Health, Environment and Safety in the Petroleum Activities of January 2002.*

Requirements in these regulations are formulated as functional requirements, whereas the guidelines recommend one way to comply with the regulatory requirement, for example a recognized standard. For coating protection, the functional requirements are stated in *Regulations Relating to Design and Outfitting of Facilities etc. in the Petroleum Activities* Section 11, while the guidelines propose *NORSOK Standard M-501* as the means to be in compliance with the regulation.

Improvements of Health, Safety and Working Environment in Coatings Application

A noise study was initiated in 1997 in order to evaluate the noise exposure for personnel working with sandblasting and ultra-high pressure (UHP) waterblasting.

The report issued in 1998, documented that personnel involved in surface treatment is the group which is most exposed to noise of all the offshore workers. This is a working environment problem, which is common to the industry, both offshore and onshore.

At the time of conducting the study, offshore work in the Norwegian sector was governed by *Regulations Relating to Systematic Follow-up of the Working Environment in the Petroleum Activities of March 1995*. These regulations specify both the maximum allowable noise exposure and requirements for personal protective equipment. According to these regulations "no employees should be subjected to a daily noise exposure which during the course of a work shift exceeds a 12-hour equivalent sound level of 83 dBA or an impulsive sound level above 130 dBC (Peak)". Personnel protective equipment shall be suitable in relation to protection against hazards without causing increased risk in itself. Further, the equipment shall be adapted to both the work place and the user.

The average noise exposure for personnel during sandblasting varies from 95 - 110 dBA with today's most common equipment in Norway, the Viking mask. The noise generated by the air supply may reach more than 105 dBA inside the mask.

Noise from the UHP waterblasting may be even higher than the sandblasting noise. Noise levels measured were as high as 110 - 130 dBA. Since working gear for UHP waterblasting has lower sound attenuation, the risk of hearing impairment is consequently even higher. Even with use of earplugs the risk of hearing impairment is present.

Working with sandblasting and UHP waterblasting will increase the occurrence of hearing impairment among the personnel. As no equipment providing sufficient protection existed in the market, there was a great need for developing new technology within working gear and personnel protective equipment.

A project was therefore initiated to develop and design new protective equipment. In addition to noise protection, the design project took into account factors as safety, ergonomics, chemical exposure and user comfort.

Personal Protective Equipment - Silencer®

Silencer® personal protective equipment has been developed in close cooperation with Norwegian sandblasting companies. The aim for the project was to develop a product that satisfied the Norwegian legal requirements to noise reduction, i.e. 12-hour equivalent sound level of 83 dBA, while still being user-friendly and comfortable. Repeated testing has shown that both goals have been attained.

The Silencer® personal protective gear for sandblasting and UHP waterblasting provide noise reduction of 39 dBA and has integrated hearing protectors and hard hat. In addition, it provides the operator with high user comfort whereas the gear has low weight (2.2 kg). With double hearing protection, both earplugs and hearing protectors, operators will be protected against harmful noise levels in most situations.

Field Experience with Coating Systems

NORSOK System 1- General Structure

Offshore field developments from the mid 1990's adopted the functional regulatory regime which was introduced in the beginning of that period, i.e. applying NORSOK standards where applicable. A common goal for both the industry and the authorities was to pave the way for cost effective solutions in offshore developments, which also meant speeding up the fabrication process. By applying production friendly coatings, with rapid curing time and shorter overcoating intervals, time and cost was saved at the yards.

In our contact with the operators, we learned that installations which had been in production for only a few years were experiencing coating deterioration on structures, piping and vessels. The deterioration occurred to coating system 1 H consisting of 60 µm zinc epoxy, 200 µm modified epoxy and 75 µm acrylic epoxy, and applied on installations designed for 20 - 50 years operational lifetime. We requested all operating companies to calculate and report back the extent of application and experience with the production friendly coating.

The response identified which installations, both offshore and onshore, where this coating system has been applied, experience with deterioration and initiated measures. A common response was that operators no longer were utilizing the said coating system. Some operators had experienced severe deterioration while other operators at that time had no such negative experience. Also, it appeared that the coating system at the time of procurement was not adequately qualified according to NORSOK M-501 requirements for pre-qualification of products. An

estimated 260 000 m^2 of structures, piping and vessels has been coated with this 1 H coating system at eight offshore installations.

The characteristic deterioration is cracking and flaking, caused by internal stress, high dry film thickness and a weak anchor pattern, indicating that the applied coating system is not capable of withstanding operational conditions.

Corrective repair programs and maintenance have been initiated years in advance of what was planned for in design. The repair systems have been pre-qualified according to requirements in NORSOK M-501. Operating companies that have commenced a repair program, experience that this is a costly and time consuming operation with progress limited by access restrictions to certain areas, limited bed capacity in the living quarter, extra caretaking of operators' occupational health while using ultrahigh pressure waterblasting for paint removal, weather conditions restricting repair work to summer months only, among others.

One operating company has incorporated additional requirements for NORSOK System 1, requiring that it must consist of a minimum of three coating layers and that corrosion creep from scribe must be less than 1.0 mm. NORSOK M-501 has no minimum requirement related to amount of coating layers, and an allowance of less than 3.0 mm corrosion creep, respectively.

NORSOK System 2 - Thermally Sprayed Aluminium

The example is from experience with thermally sprayed aluminium on risers. These risers were installed offshore along with a jacket in 1998. The risers are 12 inch and the coating systems consist of 2 x 750 μm glass flake polyester in the atmospheric zone, minimum 200 μm thermally sprayed aluminium and 12 mm polychloroprene (rubber coating) in the splash zone and 2 x 225 μm epoxy mastic below water.

After five years of service, severe corrosion was revealed on three production risers and one gas lift riser, located from the transition above and below the rubber lined riser and the painted riser.

In addition, O. Ø. Knudsen et al. reports of examples from offshore installations were thermally sprayed aluminium duplex coating systems have degraded severely after only a few years of exposure.

As a suggested degradation mechanism, it is likely that a riser coating with thermally sprayed aluminium overlaid with organic material causes aluminium to corrode and release aluminium chlorides. This in turn generates hydrochloric acid resulting in steel corrosion. As for the mentioned risers, corrosion both under the rubber and in the coating system above is evident and supports the analysis.

When specifications for the riser coating system where settled, no benefits from industry learning was available.

Thermally sprayed aluminium with only a thin sealer, has given very good corrosion resistance and little coating degradation even after very long exposure. This is explained as the sealer is too thin to hold an aggressive electrolyte at the metal surface. When the thermally sprayed aluminium corrodes the aluminium ions are precipitated as aluminium oxide, which contribute to the protection of the thermally sprayed aluminium.

Tests conducted, related to diffusion rates on chloride ions through the riser rubber coating to the thermally sprayed aluminium underneath, shows low transport rate of ions with high resistivity in the coating. Provided that the existing rubber coating remains undamaged, it will sustain adequate protection of risers for the remaining field life.

NORSOK System 3 - Applied in Tanks for Stabilized Crude

The example is from experience with coating in cargo tanks of a Floating Production Storage and Offloading (FPSO) vessel. The coating system for the cargo tanks was designed by the vessel designer in accordance to general specifications in NORSOK M-501, which recommended solvent free epoxy mastic of 3 x 150 μm thickness. However, the applied coating system at the yard was a solvent free epoxy that was to be applied in 2 x 225 μm thickness.

The FPSO was put in operation in 1997, while inspection of cargo tanks in 1999 revealed cracking of coating at tank bottom and the lower parts of cargo tanks. Further, the coating in these areas had loosened from the steel surface. To prevent damage to offloading pumps and inspect for possible structural damage, the operator decided to remove all coating in two cargo tanks.

Investigation revealed coating film thickness of up to 6 mm, whereas the specification stated maximum film thickness of 0.45 mm. The applied solvent free epoxy should normally be sprayed on by use of a two-component gun, which allows for excess thickness without compromising the quality of the coating system. At the yard, curing additives and base were mixed and solvents added prior to application, using a conventional high-pressure gun, while spraying onto ambient tropical temperature (warm) steel surfaces.

The rapid curing of the coating, before evaporation of solvents, resulted in excess solvent inside the coating. Later, when the solvent evaporated, this caused a material loss leading to contraction and stress inside the coating. In addition a high coating film thickness amplified the effect. The stress may result in cracking, or cause the coating to loosen from concave shaped surfaces.

Underneath the loosened coating, pitting corrosion with up to 60 percent wall thickness reduction was observed. It is believed that the pitting was initiated by sulphur reducing bacteria (SRB's) causing HZS corrosion.

The operating company decided to remove the coating, clean and re-coat all cargo tanks, an operation that commenced with two cargo tanks the same year loosening and cracking was discovered, and which will be finalized in spring 2004. Since cargo-filling restrictions are enforced, tank renovation is conducted during the winter period.

What Will Corrosion Protection Look Like in the Future?

Striving to develop coating systems more robust, more "user-friendly" related to applicability, more flexible related to changing environmental loads, etc., will continue, and possibly accelerate. The industry, both petroleum, aerospace, chemical, automobile and others are already searching for coating systems that we will characterize as "intelligent" coating systems, encompassing the ability to transform its abilities dependent on temperature, chemical exposure, wear, stress or strain in the material to be protected, and also including the ability to repair itself after being damaged - without being a threat to the environment.

Based on the market demand and the exponential increase in patents and publications related to nanotechnology and nanocatalysis, we foresee a development where within the next ten years we will see nanotechnology utilized in sophisticated new coating systems encompassing several of the qualities mentioned above.

Conclusions

Regulations for coatings and coatings application have over the last decade seen a shift from prescriptive requirements to functional requirements, whereas the guidelines recommend one way to comply by using NORSOK M-501 as a recognized standard.

Personnel involved in surface treatment is the group which is most exposed to noise of all the offshore workers. This is a working environment problem, which is common to the industry, both offshore and onshore. Silencer® personal protective equipment has been developed to satisfy the Norwegian legal requirements to noise reduction while still being user-friendly and comfortable.

Application of a coating system that was not adequately qualified according to NORSOK M-501 requirements for pre-qualification, have led to initiation of

corrective repair programs and maintenance years in advance of what was planned during design.

Thermally sprayed aluminium overlaid with an organic material (rubber) exposed to a marine atmosphere has shown corrosion in the transition above and below the rubber. Research has shown that aluminium chlorides are released and hydrochloric acid generated, resulting in steel corrosion.

Coating in cargo tanks has been applied in excess thickness and not in accordance to specifications, leading to loosening and cracking of the coating in operation mode. A renovations program has been initiated for the cargo tanks.

We foresee a development where striving to develop coating systems more robust, more "user-friendly" related to applicability, more flexible related to changing environmental loads, etc., will continue, and possibly accelerate.

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Section 4

White Papers

US Shipyard Paint Shops
Current Issues and Future Needs

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Introduction

The following paper was developed from discussions held during the above workshop, from discussions with US paint shop management and engineering personnel from new construction and repair shipyards that are members of the NSRP, and from technical reports developed by the NSRP SP-3 Panel. The discussion group during the workshop consisted of shipyard representatives, ship owners, coating suppliers, marine industry consultants, and research and development personnel. The group took a global view of the issues and agreed that while all the issues raised may not be immediately or easily solvable, it is vital to the shipbuilding and repair industry that these issues be worked on.

The major topics discussed at the workshop were as follows:

1. Ship Design and Preservation
2. Paint Chemistry Issues
3. Shipyard Planning and Preservation
4. Surface Preparation Issues
5. Paint Application Issues
6. Quality Assurance & Training Issues
7. Environmental Issues

Ship Design and Preservation

Many of the difficulties experienced during surface preparation and painting of ships and some of the coating failures in service can be traced back to initial design choices. A wide variety of parameters must be resolved during design of a ship such as performance requirements, material and labor costs, producibility, shipyard capabilities, maintenance requirements while in service, allowance for future changes, environmental regulations, international standards, etc. There are also distinct differences between the requirements for commercial versus military ships. Because no one parameter can have complete dominance over all others, the final design of a ship is typically a compromise. There is also a

clear trade-off between using best practices for ship design and staying within the allotted budgets for design, construction and repair. Even in the compromise, some issues must have priority. For example, the performance and initial new-build cost control requirements typically have greater priority over the other parameters. Unfortunately, it often appears that the last thing considered during the design of ships is corrosion control and coatings.

In recent years there has been a heightened awareness of how a lack of attention to ship design details can significantly increase the downstream ownership costs relative to preservation. It has been reported that the costs for preservation maintenance on US Navy ships in the fleet may be as high as 25 percent of total maintenance costs. A portion of that cost is believed to be due to the lack of sufficient attention to those design factors that impact preservation work such as:

- accessibility to perform proper surface preparation and painting during construction and when in service
- proper specification of materials (carbon steels, corrosion resistant metals, coatings, etc.)
- design requirements that lead to fabrication methods and sequences that damage completed coatings
- insufficient quality assurance specified in the preservation design

Other design related issues that affect preservation efforts and costs involve:

- There are relatively few corrosion control design standards that are sufficiently detailed to support decision making during the design of all parts of the ship. Standards for corrosion prevention of ship's structures are somewhat available, but design standards for corrosion prevention of ship's machinery, piping and electrical systems are not. Specific examples of problem areas on ships are: (1) in tanks, stiffeners that lack sufficient depth to allow access for surface preparation and coatings, (2) designs that do not support easy and simple setup and removal of the scaffolding needed for preservation, (3) angle irons that are too small and too closely spaced, (4) not enough accesses into tanks and confined spaces so that one can be used for personnel access and one for the myriad of hoses, cables and ventilation trunks needed to do the preservation work.

- Ship designs typically lack sufficient corrosion prevention details for each and every part to be painted. It is relatively easy to define the preservation requirements for major structures and components, but much more labor intensive and costly during the design phase to define the requirements down to the individual piece or part. Large combatant ships could have tens of thousands of individual parts that need paint details specified. For mechanical components, masking details for surfaces not to be painted (e.g., alignment critical and bearing surfaces) take time and attention to create. Failure to develop these details in depth during the initial design means more

time will be spent (and costs incurred) during the actual preservation work for new construction or repair.

- The design data for the ship preservation requirements must be organized in a way that can support bidding and estimating (surface area, gallons needed, surface prep costs relative to similar configurations, etc.), support development of paint procurement schedules, and help tie paint deliveries to key event dates for painting. Ship design computer software programs are just beginning to consider how to support the above issues.

- Ship designers need more feedback from ship owners and from operating ships regarding the cause of the corrosion relative to the ship design or fabrication strategy. Without such information, many corrosion problems and their associated costs for repair are likely to recur on later ships of the same class or where the same design is used on other classes. Upon evaluation, many corrosion problems experienced on ships can often be traced back to either faulty initial design decisions or fabrication strategies that "sow the seeds" for coating failure later.

- Paint warrantees for ships and their effect on design decisions are starting to be considered, but there needs to be greater education for designers in this area. Poor design choices can result in the building yard being charged to repair coating systems that failed prematurely.

- Before a new design is signed off, there should be a more formal review of any ship structure, component or system that had a history of corrosion problems on previous designs.

- There should more training in corrosion control methods for ship designers and engineers.

Paint Chemistry Issues

The key parameters the working group desired for ship coatings were:

- Less toxic
- Solventless
- Epoxy paints with better ultraviolet light resistance
- Better tolerance to high humidity during application
- Less moisture transmission
- Need minimal surface preparation
- Won't propagate at breaks in the coating
- Better shear resistance
- Better non-copper based antifouling paints

Shipyards for large ships typically apply weld-through inorganic zinc "pre-construction primers" to large steel plates and shapes prior to fabrication of the ship sections. After hull erection, the pre-construction primer is often completely removed by abrasive blasting and the final paint system for the area applied. There is a need to continue to push "weld through" paint technology to allow thicker and more durable primer coatings to be applied to the steel plates prior to initial fabrication. The new primers must be capable of surviving the construction period and allow for topcoating with the finish paint with a minimal amount of surface preparation, and without complete removal, which means the new primers should also be easier to clean. Achieving these goals could significantly reduce the cost of coating large ships.

Another issue for paint chemistry is the need for shorter drying times. Reformulation of paints in the 1990's to meet new environmental limits for volatile organic compounds (VOCs) often resulted in many interior alkyd enamels having significantly longer drying times, especially at cooler temperatures. In the shipbuilding industry, anything that can reduce the schedule for building or repairing the ship reduces cost. Paints that dry hard more quickly allow other trades back into the area sooner and are less likely to suffer damage from other construction activities, which means less re-work.

The shipyards also need paints that cure harder and are more resistant to mechanical damage. The construction and repair periods for ships can be in some ways more damaging to the coating systems than the service time due to welding, grinding, burning, machining, and system testing. Coatings that can better survive the shipbuilding and repair periods will likely also provide better performance in service, and hence, reduce re-work and maintenance costs.

Shipyard Strategic Planning and Preservation

In order for ship preservation work to provide the service life intended by the designers and expected by the ship owner, the efforts of the paint shops have to be properly coordinated with the rest of the new construction and repair requirements. The strategies for new ship construction painting are different than those for repair shipyards. New construction ships typically have a long building period and painting has to be inserted into the right times in that long span. Repairs yards typically have to accomplish painting over a much shorter period, but have mostly complete structures to coat, versus the thousands of small parts encountered in shipyards for new ships.

The process of moving parts through the paint shops for surface preparation preservation and on to the next shipyard trade for further work or installation must be a smooth one. To achieve a balanced and smooth operation, proper sequencing and planning of all construction and repair work is critical. Parts arriving at the paint shops must be properly identified relative to surface

preparation requirements, areas to be protected from paint, type and thickness of paint to be applied, etc.

For shipboard work, the paint shop is often the last group allowed in a compartment after the other trades have completed their work and hence, painting becomes the "rate limiting step" in the drive to complete the ship on time and within budget. It is also known by shipyard paint shops that many of the other shipyard trades do not fully understand the requirements for surface preparation, coating application and curing, and hence do not appreciate the negative impact their activities (and lack of control on whether steel work has been completed) can have on preservation work. This issue has been expressed as "The number of times a painter has to keep going back to the same space to repair the new coating that every one thought we were ready for". Rework caused by painting areas not completely outfitted for reasons such as incomplete hot-work, improper sequence of work, or late authorized design changes, continues to be a cost to the paint shops.

It would be unthinkable for shipyard trades to arbitrarily reduce the thickness of steel required by the designer or to choose to not install the full length of weld required. Yet shipyard paint shops are regularly asked if curing times and number of coats of paint can be reduced, or are asked to work to schedules that are shorter than paint manufacturer's recommendations. It would be beneficial to have more precise input to overall ship new construction and repair planning and scheduling to account for more realistic times required for proper surface preparation and painting, including all the activities incidental to this work, such as clean up of spent abrasive, hook-up of dehumidification equipment, quality assurance checks, etc.

The schedule for building or repairing the ship must also determine the best time during the overall sequence of activities to perform the work. For every ship structure or component, there is an optimum window of opportunity within the fabrication schedule to perform surface preparation and painting. Costs and the risk for less than desired paint performance are increased when surface preparation and operations must be performed outside that optimum window of opportunity. For example, if a structure is coated too soon in the fabrication sequence, damage to the paint and subsequent paint re-work are inevitable. The touchup work may not perform as well as the initial work because abrasive blasting may not be practical late in construction. Likewise, abrasive blasting costs will be significantly increased when the preparation work has been delayed until after machinery has been installed due to the increased labor time for masking and protection of that equipment.

Surface Preparation Issues

Surface preparation continues to be the most important and least appreciated of all the requirements of shipyard paint shops. The longevity of the applied coating system is directly related to the quality of surface preparation. For ships, surfaces that will be in immersed, wetted or damp conditions must be abrasive blasted to a minimum of "near-white" metal prior to painting. Abrasive blasting is still done primarily by individuals holding high-pressure air hoses while working from scaffolding or "cherry pickers". Automated blasting has been tested on the relatively smooth areas on the exterior hulls of ships, but is presently impractical for most topside or interior areas of ships. The labor hours to collect and remove spent abrasives and prepare the area for paint continues to be a significant cost driver. Recyclable abrasives are used in shop blasting and are being introduced for interior tank painting and exterior hulls as cost reduction and environmental improvements, but the up-front capital costs for the recyclable equipment can be intimidating even when the return on investment (ROI) appears favorable. In addition, there is a need to standardize the test requirements to ensure that recycled abrasives continue to be fit for use and to have methods that can effectively clean and prepare for reuse those abrasives in a shipyard environment

Another need is for better mechanical surface preparation tools that can be used when abrasive blasting is impractical, but that will also provide coating bond strengths equivalent to those achieved with blasting. Some shipyards report being required to accomplish the Steel Structures Painting Council's (SSPC) SP10 "near-white metal" surface standard to damaged areas of any size as opposed to a more cost-effective SSPC-SP 11 "power tool clean to bare metal". This is partly because of the lack of confidence in the ability of the mechanical tools to achieve the desired surface cleanliness and profile to support long term good paint performance. In addition, while the SSPC-SP10 standard is most commonly specified for immersed or wetted areas, there needs to be more study to determine if lesser grades of surface preparation can provide the desired level of performance when applying the latest formulations of paint. In other words, it is possible that the level of surface preparation required may exceed the amount needed when applying today's coatings.

Another surface preparation issue involves overcoating of aged epoxy systems. Many times shipyards are faced with the need to use ultra high pressure (UHP) water blasting for removal of epoxy coatings and yet maintain a suitable surface for recoating. UPH has been known to create small fractures in the existing epoxy system due to the "mass" impact of the water on the epoxy surface. Also, the required profile may not be left after blasting with water. For these reasons, a combination of techniques is often needed to ensure surfaces can be successfully re-coated.

The working group also expressed a desire for "hand-sized" hydroblast equipment and better standards and equipment for "one pass" edge grinding of steel structures.

Paint Application Issues

Over the last eight years, shipyards have started using more plural component spray equipment and proportional mixers for multi-component paints as compared to standard single pump airless spray equipment. Some shipyards report significant savings from reduced paint waste and decreased use of solvents for cleaning spray lines when using the plural component equipment. Guidelines for training workers on this equipment have been developed and certification programs are being investigated. Unfortunately, too much of the surface area on ships is still painted with brushes and rollers, which means reduced productivity and higher costs.

Other paint application issues for shipyards are:

- Capture and or elimination of overspray generated during paint application. The use of a capture device at the spray gun versus total encapsulation of the space to be painted should be investigated.

- There is a need for coating systems, including non-skid deck systems, that will last when applied over less than perfect surface preparations.

- Increase the investment in coating application technology R&D. The cost of surface preparation and coating application for underwater hull areas is going up and the designs of coating technology for this area has not kept pace.

- The shipyards need paints with longer windows for overcoating and that require minimal surface preparation if the overcoating window is exceeded. The cost of missing the overcoat window is extremely high.

- Application of 100% solids coatings outside of the paint shop facilities increases the workload due to the need for stringent environmental controls. These coatings typically have a very narrow range of fluid temperatures that will support successful spraying. As an example, plural component spray equipment often must be set-up on weather decks that are unheated, so there is an extra cost to build and heat an enclosure for the paint and the spray pumps.

- Touch up of high solids epoxy paints is more difficult due to the typically short pot life and exothermic properties of these coatings. Some promising work is underway to provide touch-up paint in pre-packaged kits that can be dispensed in just the amounts needed at the jobsite. Even so, some high

solids epoxy coatings have short pot lives that make brush or roller application difficult.

- Obtaining proper paint thickness in tight, configured structures is a problem when spraying high viscosity paints due to the high pressures required to properly atomize these coatings.

- For 100% solids paints, the increased thickness at which these paints are applied, combined with their hardness after curing, makes removal of masking very difficult.

- Paint shop workers need better and longer lasting personal protective equipment for blasting and painting, such as soundproof helmets and body cooling devices. Some shipyards use air-conditioned “waiting rooms” to rest personnel working in tanks and confined spaces.

- Robotic equipment for paint application on the exterior hulls of ships is under development by the US Navy and others. The potential exists that such equipment could be more efficient and provide more uniform paint films than humans can. The business case to support use of this type of equipment, which is typically expensive, must be developed.

Quality Assurance and Training Issues

Education and training of paint shop and quality assurance (QA) personnel are an essential part of reducing shipyard costs. The basic and advanced concepts of surface preparation and painting must be taught to all new paint and blast shop workers and continually refreshed to experienced workers. As coating chemistry becomes more sophisticated to meet environmental regulations and as surface preparation and coating application equipment becomes more complex and expensive, the investment in education and training will result in reduced costs for materials and equipment, fewer mistakes and re-work, and improved productivity.

A key component of quality assurance is related to paint shop procedures, and in particular to how those procedures flow down to the workers. Some large US shipyard paint shops have between 300 to 800 painters, so ensuring good quality paint work means somehow translating the required surface preparation and paint application information to individuals in a easy to access and clear manner. Records for accomplishment of individual procedural steps and quality assurance checkpoints need to be more computerized. On-the-job training for blasters and spray painters is a must because such activities cannot be simulated on a computer in any meaningful way. In many areas of the country, training needs to be provided in several languages.

One of the biggest challenges for shipyards will be in retaining qualified personnel to do abrasive blasting. The nature of this work is hot, dirty, noisy and dangerous. Personnel must be dressed in protective clothing for long periods and work in very uncomfortable conditions. Because coating longevity is directly related to the quality of the surface preparation more than any other paint shop parameter, shipyards must make special efforts to train and retain capable blast personnel.

The introduction of plural component spray equipment into shipyards has required increased training. Plural component proportioning equipment can expensive, often costing up to $70,000 for a single spray rig. Some units use computers to ensure a proper mix of the resin and catalyst components. The capital expended to purchase this equipment will be wasted if training is not performed regularly. Motivating paint shop workers to embrace new technology and procedures is often a challenge. People become comfortable with what they know (or think they know). As an example, in one shipyard assignment for training on plural component spray equipment was often seen by the trainees as a significant potential risk for failure rather than an opportunity to learn a new skill. The US Navy is considering a certification program for personnel who operate plural component spray equipment.

Another issue involves quality of work and oversight. Quality assurance inspectors do not always have sufficient training or are not given sufficient responsibility and authority to stop work without the fear of retaliation, which results in a lack of true third party QA. Another issue occurs when coating inspectors with minimal knowledge and experience are assigned to perform QA on major projects and who then over-assert their limitations. Some of this problem can also be related in imprecise specifications that leave too much room for interpretation. It was the consensus of the group that QA inspectors should have previous hands-on experience as blasters and painters.

Receipt inspection of paints is vital in order to have a successful preservation system. While paint manufacturers typically perform a series of conformance checks on paint before shipment, it is in the shipyards' interest to verify that only good quality paint is used for the work. The cost and time to perform receipt inspection of paint, either on an "every batch" or "skip-lot" basis, can easily be exceeded by just one crisis in a shipyard where poor quality paint has been applied. One reason for this large effect is that the existence of bad paint on a ship, and the efforts to remove it and re-apply good paint, can affect many other shipyard trades' work and schedules. For example, installed components may have to be removed and system tests may have to be repeated.

The most important need for training identified in a 1999 survey of large US shipyards was for paint shop personnel involved in cost identification and control. This attribute is seen as one of the weakest in most paint shops' capabilities. In order to control costs, one must be able to identify, calculate, and accurately report those costs to management. However, few yards have been given the

training, tools and personnel to perform this task to the degree it deserves. For that reason it is suspected that many hidden costs and potential savings are not being identified because of lack of sufficient training of paint shop personnel in this area. “Lean manufacturing”, “six sigma” and similar concepts are making their way through the US shipyard paint shops, but these efforts will not necessarily capture the key areas where training will make the difference.

Other key needs identified by the working group that are related to quality assurance and training included:

- Better mockups for training blasters and painters.
- Blasting and painting procedures must be defined simply.
- Pre-job conferences for blasters and painters are vital for success of a project.

Environmental Issues

By any measure, it can be said that the large US shipyards and the paint companies that supply them have successfully adapted to the federal EPA’s National Emission Standards for Hazardous Air Pollutants (NESHAP) from painting during shipbuilding and ship repair. Paints with compliant volatile organic compound (VOC) contents are available to serve most, although not all, the needs of the industry. There are still some specialized coatings for which VOC-compliant versions are sometimes difficult to find (for example, varnishes for electrical windings and components), primarily because the low volume usage of such coatings in the shipyards does not encourage development and approval of new compliant coatings by the paint manufacturers. Any reductions in the current limits in VOC content will cause a new round of testing and experimentation to ensure the new products will perform as well and will support ship construction and repair producibility parameters to at least the same degree as the present coatings.

A continuing issue for US shipyards involves the regulatory requirements to keep detailed records of paint usage and insure that all applicable federal and state environmental regulations are complied with. Because federal, state and regional environmental regulations for paint often read differently, paint shops must be continually vigilant to ensure compliance. Some ships require more than 100 different coatings and new ships can be constructed over as long as seven years, so paint usage databases need to be more fully computerized and inexpensive to manage. It would be helpful to the shipyard’s documentation processes if a national uniform bar code standard was established for shipyard paints. The bar code should contain information about the paint chemistry relative to the percent weight of the volatile organic compounds and hazardous air pollutants, specific gravity, batch number, container size, dates of manufacture and expiration, date of the Material Safety Data Sheet (MSDS), etc.

This would allow environmental data to be accumulated electronically upon arrival of the paint at the shipyard, and that data "rolled up" to the periodic reports required by the government agencies. The bar code would also support better tracking of the paint while in the shipyard relative to traceability to design requirements, shelf life, material usage and disposal.

Better methods are needed to separate waste paint, blasting grit and waste solvents. Better methods are also needed to predict the amount of waste to be created from the work to be done. The amount of paint and blasting grit needed must be factored into all parts of the operation (e.g., bidding and estimating, planning, re-work, cost, schedule, etc.).

Summary

The oceans are unforgiving relative to corrosion on ships. This paper has identified the key preservation issues confronting the shipbuilding and ship repair industries in their attempt to meet that challenge. In order to preserve the value of ships and ensure the safety of their crew and cargo, ships need cost-effective preservation systems that can perform well under a variety of harsh conditions. Proper corrosion control designs, smart strategies for preserving ships during new construction and repair, practical and durable surface preparation and paint application tools, and good quality assurance and training are all necessary to achieve that result.

"Rationalization and Optimization of Coatings Maintenance Programs for Corrosion Management on Offshore Platforms"

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A "white paper discussion" on the challenges of corrosion management in the offshore environment, and the opportunities presented through cooperation among energy industry operators, coatings industry vendors, and government regulators.

Introduction

The purpose of this document is to generate discussion among interested parties on the topic of corrosion management on offshore structures. It is intended that this "white paper" will grow over the next week, during the workshop and beyond into a set of recommendation for industry and regulators to use for effective management of the practice of using coatings for corrosion management on offshore structures.

Interest in the topic of corrosion management and funding for this workshop were supplied by the Minerals Management Service (MMS). Recently, the MMS has required offshore operators to report the condition of platform coating systems, a primary tool in the corrosion management of offshore platforms Results are reported as part of the annual topsides inspection reporting (API RP2A Section 14 - Level 1 Inspection). Significant questions arose concerning the criteria for reporting.

Corrosion Protection: State-of-Practice

Protecting against corrosion on offshore structures generally comes down to preventing the oxidation of steel in the humid, salt laden environment that exists offshore. In terms of corrosion protection, platform designers in the Gulf of Mexico divide a structure into three distinct regions: underwater (immersed zone), waterline or splash zone (+/- 10 feet from MLW) and topsides (+10 feet and above).

In the *underwater or immersed zone* good practice is characterized by the use of anode based cathodic protection systems which, when properly designed and

maintained, inhibits corrosion extremely well. The integrity of these systems are annual checked by monitored the anode driven potential between the platform steel and the surrounding saltwater.

In the *splash zone*, just above and below the water line, good corrosion prevention practice is characterized by minimizing the amount of structure in the water surface plane, and wrapping structural elements that pierce the water line with barrier materials such as Monel, Tideguard, and Splashstron. Properly applied, these materials are very effective at preventing corrosion in what is considered the area of a platform with the highest potential for metal loss. Nonstructural elements such as risers, sumps, well conductors, boat landings, etc. in the splash zone may be wrapped with barrier materials or protected with multi layered coating systems. All systems in the splash zone fall prey to the mechanical damage of wave action and boat impact.

Above the splash zone the platform *topsides* consist of structure elements, equipment and piping, wells, etc. Topsides elements are generally protected against corrosion by coatings. **This white paper and the workshop are focused on issues and practice associated with these coating and the role they play in Corrosion Management of Offshore Platforms.**

I. - Corrosion Management (Initial Coating)

No discussion on corrosion management, and specifically on the life of coating systems, can start without acknowledging the value of proper selection and application of the original coating system. The offshore industry can and will continue to focus on materials, surface preparation, proper application, inspection and testing. Coating inspectors and coating applicators must understand and aggressively apply good practice in the proper application of the original paint system. As coating materials are developed with the potential for longer life and better adhesion, the proper application of the product will be critical in meeting project metrics for corrosion management.

Workshop Topics for Discussion (Initial Coating):

- Protection of People and Environment
- Product Selection
    - Application conditions
    - Service conditions
- Surface Preparation
- Application
- Inspection
- Metrics

II. - Corrosion Management Program (Corrosion Management and Coatings Maintenance)

In general, corrosion management begins the day the structure is coated in the fabrication yard. We have already stressed the importance of the attention paid to the initial coating on the structure. However, when we consider the 20 to 40 plus years of the life of an offshore facility and the problems associated with coating repair and replacement in the offshore environment a much larger challenge arises.

Please note that we are not focused here on coatings management, but on *corrosion* management. Corrosion management is the term given to actively observing and assessing metal loss, while assuring that the functionality of the structure or process is maintained. An obvious example of the direct application of corrosion management with or without coating is the "corrosion allowance." The corrosion allowance is the additional steel the designer will add to a platform component to account for the 8-12 mills per year of corrosion. Such practice is/was common and fundamentally sound practice.

Topics for Discussion (Corrosion Management and Coatings Maintenance):

- Protection of People and Environment
- Corrosion Management
  - Inspection
  - Coating Breakdown
  - Steel Loss
    - Surface corrosion vs. Steel loss
  - Corrosion Drivers
    - Cathodic protection
    - Spurious currents
    - Corrosion cells
- Coatings Maintenance Plan
  - MMS's A, B, C descriptors
  - ChevronTexaco's A, B, C, D, E, F descriptor
  - Product Selection
    - Application Conditions
    - Service conditions
  - Surface preparation
  - Proper application
  - Inspection
  - Metrics
- Other considerations

Workshop Input

During approximately 7 hours of work group meetings, spirited discussion was held on the subject of coatings for offshore structures. Although several of the discussion topics received floor time, the work group sessions were dominated by discussion of the recent MMS request for a topsides coating systems assessment on all Gulf of Mexico platforms using an assessment classification that most platform operators found difficult to apply.

Below is a summary of the main topics discussed and an estimate of the percentage of time spent on each topic.

- **Coating/corrosion assessment criteria - 80%**
- **Need to attract people to the profession - 4%**
- **Support research on coatings - 5%**
- **Clarity of information on allowable surface chlorides - 3%**
- **High cost of new equipment - 3%**
- **Coast Guard and MMS inspectors should attend NACE training - 2%**
- **Feedback loop between consumer and coating industry - 2%**
- **Miscellaneous other – 1%**

Given the level of expertise present in the workshop and the quality of discussion the work group quickly distilled the discussion into seven (7) recommendations.

Recommendations and Discussion

Recommendation #1

- **Develop coating/corrosion assessment criteria and acceptable corrosion levels for use by corrosion engineers and regulators in the development and assessment of Asset Integrity Management Programs.**

A recent MMS initiative requiring the reporting of a "coating system assessment" on all platforms under their jurisdiction in the Gulf of Mexico was the catalyst for the work group discussion that evolved into this first recommendation. The state of practice for managing corrosion by operators could not be matched by any standard or guideline in the coatings or the corrosion industry. MMS began to realize that the offshore industry had a unique set of problems that was dealt with within an Asset Integrity Management Program in which coatings were used as a tool for corrosion management. Blasting and painting were postponed in favor of

sustaining production to meet contract obligations. Passive corrosion is tolerated provided that the functionality of the resource was not impaired.

The MMS proposed a simplified A, B, C classification as follows:

A – Good Condition, no maintenance needed within 3 years
B - Fair Condition, Maintenance will be required within 3 years
C – Poor Condition, Maintenance needed within 12 months

Operators with a Corrosion Management Plan did not find it difficult to respond to the MMS assessment request. It was a matter of extracting from the plan the list of structures that were to be painted in the next year (C's), 3 years (B's); and all the rest became A's.

This approach inevitably led to the question, "What are the criteria used for determining when a structure needed coatings maintenance". The answer to this question is wide ranging. Some used a coatings repair philosophy; while others were based on substrate corrosion activity. Few thought the Structural Steel Painting Council coatings deterioration guidelines applied.

It is suggested that a matrix approach defining corrosion assessment in terms of "coatings deterioration" and "degree of substrate corrosion" was an essential part of corrosion management. Appendix A shows an example of how such a matrix might look. Various examples of this approach were being utilized in corrosion assessment programs.

Other elements of the corrosion assessment program necessary for consistency and reproducibility in the A, B, C condition assessment for offshore platforms include:

- Component dependent corrosion assessment matrices
  - Structural elements
  - Wells
  - Piping and equipment
  - Stairs, walkways, handrails, etc.
- Location data
- Extent of corrosion by Location on the platform

Recommendation #2

- **Protection of People and Environment**

  - **Need to attract people to the profession**
    - **Year round work**
    - **Certification**

The offshore coating industry is a good place to work. Attracting and retaining quality employees has improved; given the excellent PP&E initiatives. However, attracting good, talented employees could be further improved by offering a steady weekly paycheck. Blame for lost pay is often blamed on coating materials with low tolerance to environmental conditions. In addition, both coatings contractors and clients will benefit by attracting and holding quality personnel by offering training and certification; both of which have a known impact on safety, employee morale and salary.

Recommendation #3

- **Product Selection**

  - **Support research on coatings:**
    - **That can be used year round in offshore conditions**
    - **With "inhibitor based technology"**
    - **Water Borne Epoxy**

You will always hear a recommendation for higher quality coating materials. From both the contractor and client viewpoint, research into more durable, longer life coatings that are more tolerant of the application environment are needed by industry. Coatings which can be applied year round support recommendation #2.

Recommendation #4

Surface Preparation

- **Improve the dissemination and clarity of information on allowable surface chlorides.**

Ongoing work in this arena was discussed and standards are being prepared. Efforts to disseminate the information would be forth coming. Techniques for reducing surface chlorides were also discussed.

Recommendation #5

Application

- **Use and deployment of new coating technology is hampered by high cost of new equipment. Look into what can be done to utilize existing equipment; lower the cost of new equipment; or provide the financial incentives needed.**

Although not necessarily a research topic, more an economic condition; it was noted that some of the new coating materials required application equipment that was state-of the art. Where ever possible coatings developers should consider the economic impact new equipment has on a contractor.

Recommendation #6

Inspection

- **Suggest that Coast Guard and MMS inspectors should attend NACE training to improve knowledge and consistency.**

MMS noted this need and will consider developing a training program for MMS inspectors.

Post-workshop note: MMS has acted quickly. An in-service inspector training course was developed and the first training was held first week of October 2004.

Recommendation #7

Metrics

- **Feedback loop between consumer and coating industry need to be improved. Problems are generally reported and investigated; however, successful applications rarely are investigated to confirm good practice.**

Although this is the last recommendation from the workshop, it could possibly be the most important. Continuous improvement in any industry requires a feedback loop that includes performance metrics, lessons learned, and best practice. Although examples of post project feedback can be pointed out, especially when poor performance is involved, effective feedback at critical mass does not exist. Given the economics

and competitiveness of the industry, and the fact that the consumer will benefit most from the feed back, the consumers need to take the lead in improving the situation.

Appendix A

<table>
<tr><td colspan="2" rowspan="2">Structural</td><td colspan="5">Coating deterioration</td></tr>
<tr><td>0-5%</td><td>6-10%</td><td>11-25%</td><td>26-50%</td><td>51-100%</td></tr>
<tr><td rowspan="5">Degree of substrate corrosion</td><td>None/ rust staining/light rust</td><td>A</td><td>A</td><td>A</td><td>A</td><td>A</td></tr>
<tr><td>General light rust--passive</td><td>A</td><td>A</td><td>A</td><td>A</td><td>A</td></tr>
<tr><td>Heavy rust --active</td><td>A</td><td>A</td><td>A</td><td>B</td><td>B</td></tr>
<tr><td>Deep pitting</td><td>A</td><td>B</td><td>B</td><td>B</td><td>C</td></tr>
<tr><td>Significant Metal loss</td><td>B</td><td>C</td><td>C</td><td>C</td><td>C</td></tr>
</table>

MMS Coatings Assessment Classification
as function of
Coating Deterioration and Degree of Substrate Corrosion

Table A.1 – Example of Proposed Classification Matrix.

Coatings for Pipelines

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Abstract

Following are the main R&D issues that were identified in the area of coatings for pipelines, listed in decreasing order of priority; i.e., item 1 is the top priority item for R&D. Items with the same number were ranked equally in terms of relative priority.

1. Database on Coating Performance
    - An unbiased third party will compile an industry-wide historical database on coating performance and evaluate the data critically.
2. Performance of Field-Applied Coatings
    - Effects of environmental conditions and variations in coating procedure on performance of field-applied coatings
    - Curing time compared with time to burial or immersion
    - Adhesion of field-applied coating and mill-applied coating

   Long-term field evaluation of pipeline coatings
    - A national or international program.
    - Coated pipe samples to be installed in the field at carefully selected locations representative of different environmental conditions.
    - Several monitoring methods to be used.
    - In addition, evaluate coating performance at constant and fluctuating temperatures with transient and cyclic temperature fluctuations.
    - 1-day scoping meeting to be held, most likely in the fall of 2004
3. Effects of stockpiling on coating performance
    - Temperature
    - UV
    - Time

   Development of practices for evaluating coatings for service under extreme conditions
    - Offshore, deep-sea
    - Onshore Arctic
    - Onshore Equator
    - Include 3 types of coatings:

Anti-corrosion coatings,
Abrasion-resistant coatings, and
Insulation coatings

4. Standardization of test methods for evaluating coatings
   Development of coatings with anti-microbial properties

Introduction

Coating performance depends on the events taking place during the five stages of the coating lifetime:

1. Manufacture,
2. Application,
3. Transportation,
4. Installation, and
5. Field operation.

Objectives of R&D are to clarify the following issues[1-3]:

- What are the chemical and electrochemical conditions and their changes under realistic pipeline environments?
- What are the conditions that are independent of coating type?
- What are the conditions that depend on coating type?
- What are the failure modes of coatings on an operating pipeline?
- How are the failure modes identified?
- How accurate are the field monitoring techniques?
- Do the standard tests simulate the chemical and electrochemical conditions of the field environments?
- Do the standard laboratory tests simulate the failure modes in the field?
- Are the acceleration effects (e.g., aging, extreme CP potential, and elevated temperature) in the laboratory tests relevant to field conditions?
- What information from the laboratory data could be transferred to field performance?
- What are the assumptions to be made to transfer the data?
- How is the validity of the prediction of field performance monitored and verified in the field?

The state-of-the-art on our understanding of performance of pipeline coatings is discussed in this white paper, along with R&D to be carried out to address the main issues. The R&D topics were prioritized at the Workshop, and the results of the prioritization are presented in this paper.

<u>Manufacture of Chemical Components</u>

Figure 1 lists the coatings used in different time periods in the twentieth century[4-64]. A comprehensive laboratory analysis of factors leading to coating failure[63]

and loss of adhesion[64] has been performed. Some of the earliest coatings applied are still in service and are still available for application on new pipelines. Over a decade ago, the concept of polyurea spray elastomer technology was introduced. This new application was based on the reaction of an iso-cyanate component with an amine blend. Advances in both the chemistry and application equipment for coatings have enabled continuous evolution of coatings.

Coating Chemistry

Although finger printing of the products is used for quality control (QC) purposes, this method is not 100% reliable.

- X The relationship between coating chemistry and corrosion protection is not clear.

Previous investigations were undertaken to explore any possible effects of cathodic protection to disbond pipeline coatings. These studies focused on the electrochemical reactions and chemical changes that occur in the environment at the steel surface and characterized, using Fourier Transform Infrared (FTIR), Auger electron spectroscopy (AES) and X-ray photoelectron spectroscopy (XPS), the surface chemistry of steel samples taken from areas where the coating was disbonded.

Simple test procedures have been developed to assess[65]:

1. The degree of reaction (cure) of the applied FBE (fusion bonded epoxy) coating,
2. The adhesive bond strength of the coating to the steel pipe substrate, and
3. The void content of the coating created by bubble entrapment or gas formation during application.

All investigations were carried out using FBE coating as the model system[66-72].

Filling the gaps in knowledge requires that the manufacturers be willing to disclose not only the coating formulations but also the ratios in which the different components are present in the formulations. Within the composition range of generic coatings, the formulations change widely without any significant change in the corrosion protection properties. Although a relationship between coating chemistry and corrosion protection is important, any attempt to fill this gap will involve significant R&D.

Laboratory Evaluation

Evaluation of existing coatings is the first important step in the development of future coatings. Several methods have been used over the years to evaluate the

tests. Table 1 presents a list of standard tests that can be used to evaluate coatings. The standards are the widely accepted baselines, although further improvement and consolidation of various national standards are needed.

It is not entirely clear which laboratory tests should be used to evaluate a particular property of a given coating and which laboratory tests are suitable for specific coatings.

- Consolidation of laboratory methods to develop generic tests, leading to specific test methods for specific coatings, should be considered.

Long-Term Prediction/Life-Time Cost

Current and potential distributions inside the crevice of a simulated disbonded coating with a holiday during cathodic protection (CP) of steel were measured experimentally[73]. Based on the comparison of experiments and numerical simulation of a cathodically protected buried pipe with coating failures, a model was developed. The agreement between the results demonstrates that numerical simulations are acceptable for cathodic protection systems in high-resistivity media[74].

Two- and three-dimensional boundary element mathematical models have been developed to model the performance of CP designs. The models offer a convenient tool to quantify the performance of a CP system and allow the user to determine the influence of relevant parameters, such as soil resistivity, coating damage, and anode type and spacing. The model can also be used as an educational tool to identify the factors that control CP performance under different operating conditions[75].

A boundary element mathematical model was used to assess the influence of cathodic protection (CP) design parameters on performance of a parallel-ribbon sacrificial anode CP system for coated pipelines. The model accounted for current and potential distributions associated with discrete holidays on coated pipelines that expose bare steel to the environment. Case studies, based on the CP system used to provide protection to the Trans-Alaska pipeline, were selected to show conditions under which a given CP system will and will not protect a pipe[76].

The General Electromigration Model (GEM) has been used with modifications for electrochemical kinetics[77]. The cathodic hydrogen evolution rate and anodic iron dissolution rates were both found to affect the pH inside the crevice. The model also predicted that formation of iron carbonate, observed extensively in some pipeline failures, occurs under a specific combination of iron dissolution rate and hydrogen evolution rate. GEM provides a unique modeling tool because it is flexible enough to test the effects of a variety of environmental conditions as

input parameters and because its predictions of solid mineral formation in crevices can be tested against field experience. The changes in crevice pH and potential were measured experimentally using microelectrodes.

The occurrence of corrosion and stress corrosion cracking (SCC) under a disbonded coating on a pipeline is determined by a variety of factors including groundwater composition, soil conditions, presence of alternating wet/dry conditions, coating type, cathodic protection, and operating conditions. The Transient Electrochemical Coupled Transport (TECTRAN) code predicts the time evolution of the environment under a disbonded coating[78].

However in all the modeling work, the plurality of coatings has not been addressed. In one study, it was determined that for the coating thicknesses examined and over the time period observed, coal tar enamel and polyethylene tape acted as inert barriers, and no permeation or ionic migration through these coatings was observed. The FBE exhibited slight ionic migration and was found to be cation selective[79].

Electrochemical Impedance Spectroscopy (EIS) is a good tool to investigate the deterioration of coating on a metal. Electrochemical impedance spectroscopy provides two very important pieces of information: the change in capacitance of the organic film that relates to water uptake and the deviation from purely capacitive behavior of the film. For gas pipelines, the equivalent circuit parameters in the presence of disbonded coatings have been established[80]. The parameters of the model are the coating thickness and the area under the disbondment. A coated pipeline can be modeled as a sequence of simple equivalent circuits, which can be handled using standard theory to yield the observed impedance in terms of the values of the circuit elements in the line. The proposed models have been tested to verify their applicability for predicting sites of corrosion in buried pipelines. The effect of a few geometrical and physical parameters has been investigated, and results have been compared with the output of laboratory and field measurements. In some cases, the adjustment of literature parameters has been enough to obtain good agreement of field and laboratory data; modification of the equivalent circuit has, however, been found to be necessary. But there is no universally accepted method of using EIS for coating performance. Future research in this field is required before the method can be used with confidence.

Development of pores in the coating or disbonding of an electrolyte-saturated film causes deviation from capacitive behavior. For either case, conducting paths develop through the coating. Research to evaluate the nature of these conducting paths would provide valuable insight into the degradation of the coatings. Little information exists on the relationship of EIS data to the protective properties of organic coatings.

Low cost computing power is having its impact on all areas. In recent years, the use of microprocessors in the design of instrumentation has brought computing power into the hands of people working in quality control. These analytical techniques are now being applied to coatings, particularly for coating thickness assessment when continuous processing is applicable.

- A comprehensive model to predict long-term performance of coatings should be developed based on carefully controlled laboratory experiments as well as from field experience with older coatings, such as coal tar and asphalt, and modern coatings, such as FBE and urethane, using the power of modern computers and intelligent systems, e.g., artificial neural networks.

Temperature Effect

In some applications, one of the critical properties of external organic coatings is resistance to high temperature. It has been found that most organic coatings have problems at temperatures higher than 80°C. There is a need for high-temperature performance in oil and gas pipelines, especially near compressor stations for natural gas transmission and in the transport of higher viscosity crude oils. The operating temperatures of pipelines extend to 275°C. Applicators, coating manufacturers, and owners are working to overcome the challenges associated with high temperatures. Currently no industry standards exist to test high temperature coatings. Manufacturers are developing high temperature coatings based on in-house testing. It is recognized that conventional test methods, such as cathodic disbondment, may not be appropriate. The primary challenge is to obtain adequate flexibility with high temperature performance. For this reason, design criteria for high temperature test methods and for life prediction need to be established.

The criteria for testing coatings for higher temperature applications are not the same as those for lower temperature application. For example, coatings with good cathodic performance, adhesion, barrier properties, impact resistance, and flexibility will protect the pipeline over the lifetime. At elevated temperatures, cathodic disbondment performance may not be relevant if the coated pipe is insulated. But good adhesion, barrier properties, flexibility, and resistance to movement at higher temperatures are necessary.

The question is not, “How do we design the perfect high temperature coating?” Rather, it is, “How do we know that we have designed it?”

- Based on a systematic study, the temperature limits of existing tests should be explored, and tests to evaluate products for elevated temperature applications should be developed.

Application

In general, conditions are better for application of coatings in the mill than in the field. Most modern coatings are applied in the mill.

- Whereas many of the issues of mainline coatings are well understood and standards for mainline coatings have been developed, there is now a need to focus on field applied coatings, both repair and joint coatings.

Surface Preparation

Resistance of a coating to disbondment is a property affecting all forms of corrosion; an intact coating that prevents contact of electrolyte with the steel surface will mitigate all forms of corrosion. Studies show that inadequate grit blasting can increase corrosion and stress corrosion cracking susceptibility by creating stress raisers at embedded mill scale. Grit blasting produces anchor patterns suitable for adherence of coatings.

A study of atmospheric exposure of cold applied coal tar enamel coatings revealed that systems applied to wire-brushed surfaces, primed or unprimed, failed within one year. On the other hand, the same systems on sandblasted surfaces, both with and without primers, were in satisfactory condition after five years' exposure in the same environment[81].

Studies have concluded that visual evaluation (degree of blistering, rusting and creep of blistering and corrosion from a scratch) is not sufficient to predict the effect of surface condition on coating properties[82].

An investigation on the effect of surface contamination included a study of the presence of varnish or previous coating on the pipe, phosphoric acid treatment, water, and grit or shot quality. The presence of contaminants on the pipe surface was identified using EDAX (X-ray energy dispersion analysis), optical and electron microscopy analysis, grit and water conductivity, and acid wash location. The results indicate that all varnished pipes presented high cathodic disbonding (above 17 mm). This high cathodic disbonding was attributed to varnish particles located on the anchor pattern of the pipe surface. It was also found that phosphoric acid application after blasting gives better adhesion and less cathodic disbonding. This has been attributed to the surface active pattern provided by the acid that gives better interaction between the pipe surface and FBE[83].

Based on R&D to evaluate the performance of FBE coatings on contaminated and uncontaminated surfaces with and without phosphoric acid treatment, the following conclusions were drawn[84]: Acid wash treatment greatly improves the performance in CD tests if the surface was initially contaminated. Chloride

contamination is the most difficult type of contamination to remedy, because of pitting corrosion.

Based on adhesion ratings after hot-water immersion, the maximum tolerance levels of FBE coatings[85] applied over contaminated steel surfaces were at the threshold limit values: chloride (5 μg/cm^2), sulphate (7 μg/cm^2), nitrate (9 μg/cm^2), and ferrous ion (24 μg/cm^2). Accelerated performance testing of FBE coatings on ion-contaminated steel substrates revealed that the following coating parameters are functions of contaminant ion concentration: (1) tensile bond strength after hot-water immersion, (2) blister size and density after hot-water immersion, and (3) degree of disbondment after accelerated cathodic disbonding. One study of FBE coating performance was conducted using coupons removed from contaminated production pipe. The steel coupons with contaminations higher than the threshold level failed in the hot-water immersion test, whereas those with lower levels of contamination passed the test.

The use of water jetting and water cleaning has increased recently with advances in equipment technology, the continued concerns with dusting caused by abrasive blast cleaning, and a heightened awareness of the need for chemically clean substrates. NACE 5/SSPC-SP 12 was introduced in 1996 (as an update to NACE Standard RP0172) to describe levels of cleaning using water for substrates to be painted. The NACE and SSPC abrasive blast cleaning standards are well known in the coatings industry, and field inspectors are very familiar with their use and interpretation. Additionally, the blast cleaning standards clearly describe one end condition of the substrate to be painted. In contrast, NACE 5/SSPC-SP 12 describes four end conditions of the substrate for visible cleanliness and three conditions for non-visible cleanliness. As a result, the specifier must make specific choices when invoking NACE 5/SSPC-SP 12.

A review paper on the surface preparation standards in various countries was published recently with the intention of determining whether there is a prevailing or common standard in use. Discussions with users in Europe, United Kingdom, Middle East, Japan, Australia and Venezuela have revealed a trend away from national standards towards International Standards[86].

Grit blasting increased the cathodic disbonding resistance of coal-tar enamel and FBE coatings, but did not increase the cathodic disbonding resistance of polyethylene tape. Grit blasting also beneficially alters the corrosion potential of the pipe[87].

Whereas the effects of different surface preparation techniques are well established, the tolerance in the variation within the surface preparation specification is not clear. This aspect is especially important because there are limitations on the control of surface preparation that is possible in the field.

- The effects of minor variations in surface preparation on long-term coatings performance need to be established.

Temperature Effects

The intercoat adhesion of coatings cured using cross-linkers depends on both temperature and humidity. The addition of thinner promotes intercoat adhesion failure. The conversion of the amine to amine carbamate salts at or near the surface, resulting in incomplete curing at the interface, is responsible for intercoat adhesion failure.

The rate of reaction between the amine and the epoxy prepolymer, and the humidity level, are key factors in the intercoat adhesion of epoxy coatings. At appropriate temperatures of application, the rate of reaction between the amine and the epoxy prepolymer is rapid, causing the formation of coatings with good intercoat adhesion. However, at lower temperatures, the rate of the cross-linking reaction is decreased, allowing moisture to permeate the coating and solubilize the amine. In its solubilized form, the amine reacts with carbon dioxide to form stable carbamate salts incapable of reacting with the epoxy prepolymer. In addition, the degree of cross-linking also depends on the RH level to determine the degree of solubilization of the amine that can be converted to the carbamate salt. The appropriate level of applying the coating is generally determined by the glass transition temperature[88].

- Relationship between application temperature and coating performance needs to be established.

Installation of Pipeline

During installation, minor coating damage is bound to occur for various reasons. It is very important to ensure that the pipe coating is adequately tested and that all defects are repaired.

Stockpiled Coating

The breakdown of powder polyester coatings when exposed to UV radiation (270-390 nm, peak ~313 nm) has been explored by monitoring changes in their ion transport properties using impedance spectroscopy. EIS demonstrated that one manifestation of weathering was the development of an increased level of porosity in the films that could be measured quantitatively. The results from impedance spectroscopy were supported by SEM and gloss loss measurements[89].

The effect of UV on stockpiled coatings is well known. The extent to which stockpiling affects coating performance is not known.

- Influence of stockpiling on coating performance should be established.

Joint Coating

Historically, the major problems associated with field-applied coatings were directly related to the sensitivity of prevailing environmental conditions, such as substrate cleanliness and preparation, and application technique (including curing time). In addition to good "in service" performance, systems should be easy to apply and tolerant to environmental conditions. While pipeline coating plants have been developed to apply advanced coatings to strict specifications, specifications for coatings applied to field joints have not received the same emphasis.

The increase in use of high quality and expensive pipeline coatings has heightened the need for field joint coating systems to match the quality of factory coatings. A comparison should be made between the different field joint coating systems in terms of technical characteristics, cost, and ease of application in the field. Because of the lack of international standards, pre-qualification trials and production testing in the field are important.

- A systematic study on the effects of field conditions and variations of procedure during the application of joint coatings, including the field performance of the coating, is recommended. This study should include the cohesive and adhesive strength of joint coatings.

Backfilling

There are several factors relating to backfilling that influence coatings. These are soil type, drainage, topography, temperature, and electrical conductivity. The Canadian Energy Pipeline Association (CEPA) has classified the soils in Canada into seven (7) types (Table 2). Even though backfilling is very important, no systematic experimental data are currently available on the effect of backfilling on coating performance.

Fine backfill around the pipe is used to protect the pipe from heavy and sharp rocks or other objects. In addition, the system can include a layer of geotextile fabric just above the fine backfill as additional protection against damaging rocks[90].

In very rocky areas, pipeline-construction operations sometimes dictate that an external impact-resistant or barrier material be applied over the pipe to protect the coating from damage during backfilling. The use of a specific backfill, such as compacted sand, is often specified. As an alternate, a barrier coating of concrete or urethane foam can be applied over the coating. Although high resistance and resistivity are normally associated with a propensity for shielding of cathodic protection current, the resistivity of a barrier material and the corrosion rates and polarization characteristics of the underlying steel are important when considering the potential for shielding and the protection capability of the barrier material[91].

The Office of Pipeline Safety (OPS) is currently conducting two projects, "Improvements to External Corrosion Direct Assessment Methodology by Incorporating Soils Data" and "Emerging Padding and Related Pipeline Construction Practices". The projects are expected to produce benchmarks for comparison of variety of soil types, and existing as well as emerging practices, to provide a basis to assess improvements to current practices[92].

- Realistic backfill impact testing that includes a method to evaluate the compaction produced by backfilling should be carried out to determine the effect of backfilling on coating performance.

Soil Forces

Shear properties of pipeline coatings with elastomeric adhesives are frequently measured in the laboratory. These measurements are expected to correlate with the ability of the coating to withstand the forces of soil burial and movement. The parameters of the laboratory methods are based on calculations of soil forces on pipeline coatings from an analytical model and from finite element analysis[92,93].

An apparatus was designed and built to carry out peel and sheer tests at different temperatures. The peel test procedure allows for the measurement of shear strength, which is directly comparable to shear stress sustained by coatings on buried pipelines. The results have shown significant differences between the adhesion properties of individual products. The shear and peel strengths of the coatings are strongly affected, as shown by an exponential drop with increasing temperature. The results conform to an Arrhenius relationship between temperature and the peel and shear strengths[94].

In one project, existing test methods were examined to determine their applicability to horizontal directional drilling (HDD) and slip boring loads. Two generally applicable methods were identified, Technical Inspection Services' (TISI) Gouge Test and Taber Abraser Test (ASTM D 4060). Both these methods are related to the soil conditions, for which the rotary abrasion tester has been

designed. The results can be used to predict coating wear during HDD installation through rock[95].

- Focused effort to understand soil forces (both physical and chemical) on coating performance will provide useful information for developing strategies to protect coatings.

Construction of Frontier Pipelines under Extreme Temperature Conditions

Offshore deep sea pipelines may be exposed to very low temperatures (as low as –65°C). In the near future, the construction of northern pipelines for transmission of natural gas will begin in North America. Construction in the harsh northern climate, with temperatures as low as – 45°C and in remote locations will impose unique challenges for protective coatings on pipelines. Methodologies for evaluating and selecting pipeline coatings for use on pipelines under extreme conditions will have to be developed, considering the extreme climatic conditions to which the coated pipe may be subjected before it is installed and before operation begins. It is critical that the design of coatings be adequate to protect the pipelines under long-term, severe environmental conditions, including the extreme climatic conditions that will apply in the North before the pipe is installed and operation begins.

- Recommended practices for evaluating coatings for northern pipelines need to be developed and incorporated in standards

Field Testing of Coatings

Repair Coatings

A number of factors that are important in the performance of mainline coatings are also important for repair coatings, including: cathodic disbondment, adhesion, resistance to moisture penetration, impact resistance, penetration resistance, performance at service temperature, abrasion resistance, soil stress, burn-back resistance, chemical resistance, and general handling behavior. In addition, because the repair coatings are applied in the field, the factors discussed in joint coatings are also important. In spite of the importance of repair coatings, no special tests or procedures have been developed to evaluate them[96].

Correct material selection can provide substantially improved coating performance and economy. No specific method for repair coating selection exists. The development of field-proven, reliable criteria for selecting and evaluating repair coatings is essential in order to make the best use of available materials and processes. The development of accelerated tests that closely

resemble actual field application and service conditions would be useful in the realistic evaluation of repair coatings.

- Tests to evaluate repair coatings, including evaluation of cohesion within the repair coating and adhesion to the mainline coating and to steel pipe, should be developed.

Field Performance

Monitoring

Several techniques are available to detect defects in coatings on buried pipelines. A critical review and evaluation of the Pearson survey, close interval survey, coating conductance parameter, electromagnetic current attenuation, and DC voltage gradient methods have been provided, with the advantages and disadvantages of each method identified[97]. An instrumented pipeline pig designed to locate disbonded external coating on operating gas pipelines has been evaluated[98]. The results from each method have been assessed in terms of defining the need for coating refurbishment and in providing the parameters needed to establish the most cost-effective route to control pipeline corrosion.

The Elastic Wave vehicle has the potential to detect disbonding as well as areas where the coating has been removed[99,100].

The development of instrumentation for field testing and inspecting coatings has been accelerated by the use over the last ten years of microprocessor electronics. Such designs are now entering the fourth generation and have included many user features that make the assessment of coatings easier and more accurate than was previously possible. These features include storage of data, statistical analysis, hard copy printout and high accuracy in hand-held fully portable and rugged units, suitable for use in the most hazardous environments. The most recent improvements have been realised by providing the transducer, or probe, with electronic intelligence so that its characteristics can be closely matched for optimum accuracy and flexibility. A major benefit of this approach is that the measurement transducer can be of any type and the data output from the electronics can be made to fit a standard format display instrument. In this way, it is possible to make a general purpose kit with a diverse set of measurement modules for a range of tests, such as temperature, humidity, surface profile, and adhesion, as well as a full range of coating thickness modules, using electromagnetic induction and eddy currents for applications that range from thin coatings on small components up to very thick coatings on large structures.

It is becoming more common for gas transmission pipelines to share a common corridor with electric power transmission lines. Electrical energy that is

magnetically coupled from the power line often results in an AC voltage being developed between the pipeline steel and the earth that surrounds the pipeline[101].

It is important to evaluate the extent to which monitoring techniques are capable of evaluating the shielding effect of coatings.

- Development of a remote, accurate monitoring technique to evaluate the status of the coating (including the shielding effect) will greatly enhance pipeline integrity and decrease the number of pipeline incidents caused by corrosion.

Feedback

In spite of the close interaction between pipeline owners and coating suppliers at the time of installation of pipe, feedback on coating performance, whether positive or negative, is not, in general, readily available.

- Development of an industry-wide coating database to share the experience of older and modern coatings is an essential logical step to develop an integrity management program. Continuous updating and sharing of such a database will be very useful.

Operational Conditions

In general, pipeline operational conditions vary considerably. Among all the various conditions, temperature is quite important. In spite of the well-known transient temperature variations of pipelines and seasonal cyclic fluctuations, no systematic study on the effect of temperature on coatings has been carried out.

- The performance of coatings should be compared at constant and fluctuating temperatures.

Ground Effects

Although coatings are routinely evaluated for resistance to a variety of ground factors (e.g., soil stresses), few coatings have been developed with consideration given to their resistance to microbiologically influenced corrosion (MIC). Increased numbers of bacteria at some corrosion sites have been observed. A model, for the development of a site where MIC occurs, indicates that in the first phase, soil stresses caused disbondment of the coating, leaving adhesive/primer exposed to the invading water on the pipe surface. Blisters, filled with water, form in the residual coating components on the pipe surface. As the MIC community

forms and grows, pitting corrosion begins in local areas, effectively "fixing" the anodes. In the final phase, periodic exposure to oxygen results in transformation of the corrosion products (siderite and ferrous sulfides) to iron (III) oxides.

Early studies performed in the GRI MIC program demonstrated that a very high percentage of external MIC occurred in connection with disbonded coatings and followed the same general pattern as classic examples of MIC associated with disbonded coatings. The general consensus is that holidays will occur in most coatings by one or more mechanisms (mechanical, chemical, and biological) and that holidays and disbonded coatings offer sites for MIC to occur[102]. Studies have also shown that levels of bacteria are high on all types of coatings and in all holidays regardless of the level of CP and the pH in the holidays (which ranged from 4.5 to 11.9).

The effects of CP on MIC cannot be assessed simply by measuring the numbers of bacteria. Instead, chemical and site specific factors (e.g., corrosion potential of the steels in the soils at specific sites) must be taken into account.

A "first-cut" MIC profile was developed to aid in determining which sites were most likely to be susceptible to external MIC. This profile included soil, chemical, biological, metallurgical and operational factors, such as level of CP.

Several reports in the literature have confirmed the utilization of certain pipeline coatings by microorganisms. Microorganisms have the potential to enhance coating disbondment rates as well as contribute to pipeline corrosion as a result of coating biodegradation. In these studies, parameters such as coating weight loss and enumeration of microbial cells were used to assess the biodegradation of coatings. Uncertainties in causes of weight change occur because weight loss can result from solubilization of coating constituents and weight gain can be caused by water absorption. Enumeration is not a measure of activity since microorganisms can be active without increasing their numbers. Thus, enumeration cannot produce direct and quantitative results.

- An objective study to develop a method that monitors microbial population and coating biodegradation will clarify the effects of microbes on coatings.

<u>Summary</u>

At the workshop held in Biloxi, the following R&D issues were identified as top priorities. This prioritized list is very similar to one developed in a PRCI project, thus validating the importance of the conclusions reached at the Workshop[103]:

1. Database on Coating Performance
   Unbiased third party will compile an industry-wide historical database on coating performance and evaluate the data critically.

2. Performance of Field-Applied Coatings
    Effects of environmental conditions and variations in coating procedure on performance of field-applied coatings
    Curing time compared with time to burial or immersion
    Adhesion of field-applied coating and mill-applied coating
  Long-term field evaluation of pipeline coatings
    A national or international program.
    Coated pipe samples to be installed in the field at carefully selected locations representative of different environmental conditions.
    Several monitoring methods to be used.
    In addition, evaluate coating performance at constant and fluctuating temperatures with transient and cyclic temperature fluctuations.
    1-day scoping meeting to be held, most likely in the fall of 2004
3. Effects of stockpiling on coating performance
    Temperature
    UV
    Time
  Development of practices for evaluating coatings for service under extreme conditions
    Offshore, deep-sea
    Onshore Arctic
    Onshore Equator
    Include 3 types of coatings:
        Anti-corrosion coatings,
        Abrasion-resistant coatings, and
        Insulation coatings
4. Standardization of test methods for evaluating coatings
  Development of coatings with anti-microbial properties

The following issues are important, but are not considered as high priorities at this time:

- Parameters that control coating performance
- Modeling of performance of all coatings (not only FBE). Modeling using EIS is not reliable
- Evaluation of coatings at higher temperature (above 85oC) in the laboratory
- Performance of insulation coating
- Effects of minor variations in surface preparation and effects of variation in composition of surface contamination, including mill scale, on long-term coatings performance
- Method to monitor simultaneously microbial population and coating degradation

Acknowledgements

The authors gratefully acknowledge the support of the Pipeline Research Council International (PRCI) in carrying out the initial review on which this white paper was based. Numerous helpful discussions with the chair of the Ad Hoc PRCI committee, Howard R. Mitschke of Shell Global Solutions (US) Inc., are acknowledged. Meetings with the Ad Hoc Committee were most beneficial in helping to achieve the objectives of this project.

The discussions that took place at the workshop in Biloxi were most helpful in giving the authors and the workshop participants an opportunity to update and prioritize further the R&D topics. The efforts of the Workshop participants are gratefully acknowledged.

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Fig.1: Pipeline Coatings in Canada

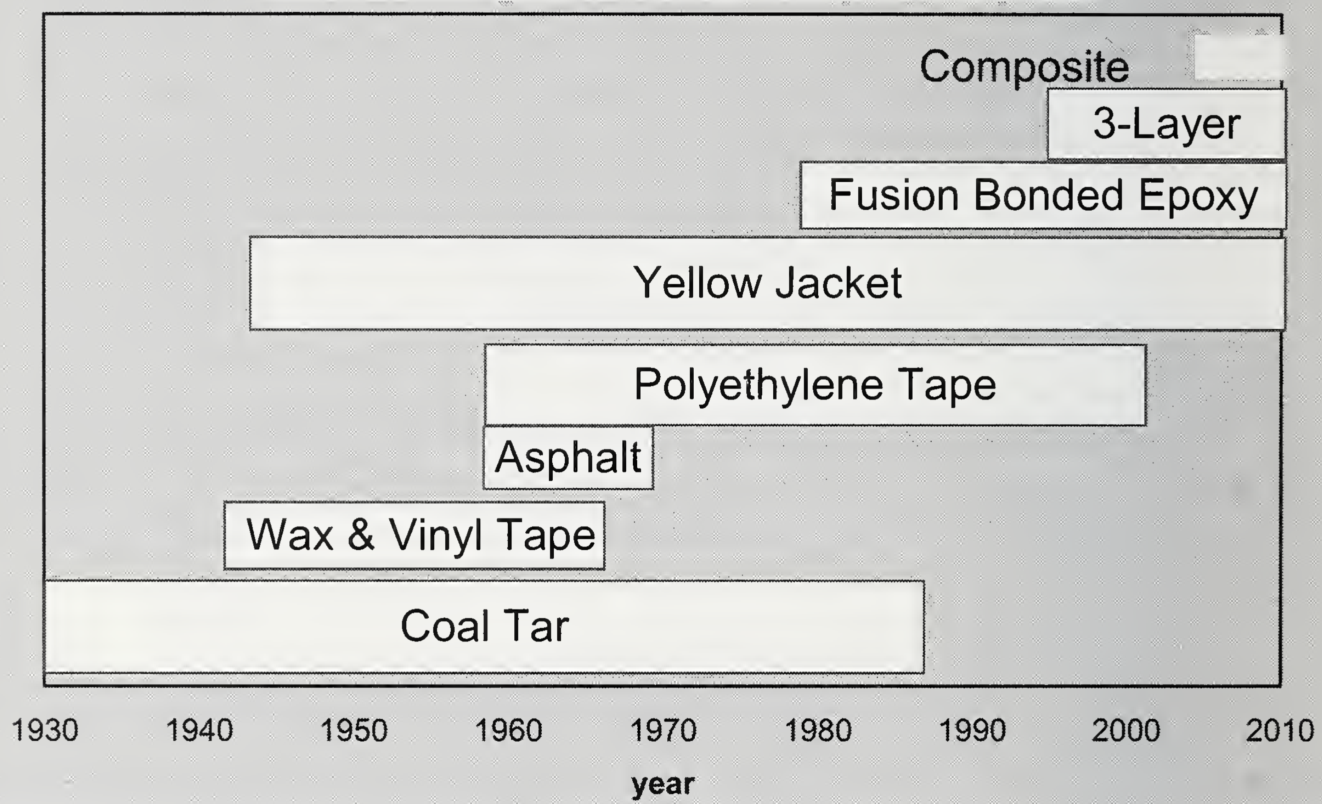

Table 1: Standard Laboratory Tests for Pipeline Coatings

Name of the test	Standard from	Information used to evaluate
Gel time	CSA Z.245.20.98 (Section 12.2)	Coating quality
Gel time	NACE RP0394-94 (Appendix D)	Coating quality
Moisture content - Titration	CSA Z.245.20.98 (Section 12.3)	Coating quality
Moisture content - Mass Loss	CSA Z.245.20.98 (Section 12.4)	Coating quality
Moisture content	NACE RP0394-94 (Appendix F)	Coating quality
Particle size	CSA Z.245.20.98 (Section 12.5)	Coating quality
Particle size	NACE RP0394-94	Coating quality
Density	CSA Z.245.20.98 (Section 12.6)	Coating quality
Density	NACE RP0394-94 (Appendix B)	Coating quality
Thermal characteristics	CSA Z.245.20.98 (Section 12.7)	Coating quality
Thermal analysis/characteristics	NACE RP0394-94 (Appendix E)	Coating quality
Cure cycle	NACE RP0394-94	Coating quality
Glass transition temperatures	NACE RP0394-94 (Appendix E)	Coating quality
Heat of reaction	NACE RP0394-94 (Appendix E)	Coating quality
Total volatile content	NACE RP0394-94 (Appendix G)	Coating quality
Interface contamination	CSA Z.245.20.98 (Section 12.15)	Coating quality
Porosity	CSA Z.245.20.98 (Section	Coating quality

	12.10)	
Porosity	ANSI/AWWA C203/97 (Section 5.3.14.4)	Coating quality
Viscosity	CSA Z245.21.98 (Section 12.1)	Coating quality
Flow	CSA Z245.21.98 (Section 12.2)	Coating quality
Cross-section porosity	NACE RP0394-94 (Appendix J)	Coating quality
Interface porosity	NACE RP0394-94 (Appendix K)	Coating quality
Interface contamination	NACE RP0394-94 (Appendix P)	Coating quality
Surface preparation	SSPC-SP6/NACE No.3	Surface preparation
Surface preparation	SSPC-SP10/NACE No.2	Surface preparation
Surface preparation	ISO 4618-3:1999	Surface Preparation - Terms and definitions for coating materials
Shelf life	NACE RP0394-94 (Appendix C)	Handling
Outdoor weathering	ASTM G 11	Handling
Water resistance (100% relative humidity)	ASTM D 2247	Handling
Flexibility	CSA Z.245.20.98 (Section 12.11)	Testing (Hydrostatic expansion)
Flexibility (2°/PD at -18°C or 1.5°/PD permanent strain)	NACE RP0394-94 (Appendix K)	Testing (Hydrostatic expansion)
Bendability	ASTM G 10	Installation
Bendability (ring) - squeeze test	ASTM G 70	Installation
Cathodic disbondment	CSA Z.245.20.98 (Section 12.8)	Operation
Cathodic disbondment of strained coating	CSA Z.245.20.98 (Section 12.13)	Operation
Cathodic disbondment (24 hours or 28 days	NACE RP0394-94 (Appendix H)	Operation

Cathodic disbondment	ASTM G 8	Operation
Cathodic disbondment	ASTM G 80	Operation
Cathodic disbondment (Attached cell method)	ASTM G 95	Operation
Cathodic disbondment (Elevated temperature)	ASTM G 42	Operation
Chemical resistance	CSA Z.245.20.98 (Section 12.9)	Operation
Chemical resistance	NACE RP0394-94 (Appendix I)	Operation
Chemical resistance	ASTM G 20	Operation
Impact resistance	CSA Z.245.20.98 (Section 12.12)	Operation
Impact resistance	NACE RP0394-94 (Appendix L)	Installation
Impact resistance (Limestone drop)	ASTM G 13	Installation
Impact resistance (falling resistance)	ASTM G 14	Installation
Impact resistance (effects of rapid deformation)	ASTM D 2794	Installation
Impact	ANSI/AWWA C203/97 (Section 5.3.7)	Installation
Impact resistance	ANSI/AWWA C214-95 (Section 5.3.10)	Installation
Adhesion	CSA Z.245.20.98 (Section 12.14)	Operation
Adhesion	ASTM D 3359	Operation
Adhesion (Constant rate of peel)	CSA Z245.21.98 (Section 12.4)	Operation
Adhesion (peel by hanging mass)	CSA Z245.21.98 (Section 12.5)	Operation
Adhesion	ANSI/AWWA C203/97 (Section 5.3.13.7)	Coating quality/operation
Adhesion	ANSI/AWWA C214-95 (Section	Coating quality/operation

	5.3	
Peel (adhesion)	ANSI/AWWA C203/97 (Section 5.3.6 and 5.3.8)	Operation
Ageing (Heat)	CSA Z245.21.98 (Section 12.6)	Operation
Strain resistance	NACE RP0394-94 (Appendix M)	Operation
Abrasion	NACE RP0394-94 (Appendix O)	Installation/Handling
Abrasion resistance	ASTM D 968	Installation/Handling
Abrasion resistance	ASTM G 6	Installation/Handling
Hot water soak	NACE RP0394-94 (Appendix N)	Operation
Water absorption	ANSI/AWWA C214-95 (Section 5.3.4)	Operation
Water-vapour transmission	ANSI/AWWA C214-95 (Section 5.3.5)	Handling
Water penetration	ASTM G 9	Operation
Penetration resistance	ASTM G 17	Operation
Penetration	ASTM G 17 at 93°C	Operation
Penetration	ANSI/AWWA C203/97 (Section 5.3.2)	Operation
Penetration	ANSI/AWWA C214-95 (Section 5.3.11)	Operation
Sag	ANSI/AWWA C203/97 (Section 5.3.4)	Operation
Pliability	ANSI/AWWA C203/97 (Section 5.3.9)	Operation
Breaking strength	ANSI/AWWA C203/97 (Section 5.3.12)	Coating quality
Softening point	ANSI/AWWA C203/97 (Section 5.3.13.4))	Coating quality
Dielectric strength	ANSI/AWWA C214-95 (Section 5.3.6)	Coating quality
Insulation resistance	ANSI/AWWA C214-95 (Section	Coating quality

	5.3.7)	
Tensile strength	ANSI/AWWA C214-95 (Section 5.3.8)	Coating quality
Elongation	ANSI/AWWA C214-95 (Section 5.3.9)	Coating quality
Steel pipes and fittings for buried or submerged pipe lines -- External and internal coating by bitumen or coal tar derived materials	ISO 5256:1985	General

Table 2: CEPA - Soil Type Descriptions

Soil Type	Description	Numeric Code
Alluvium	Various textures, utilized in this classification for mountainous areas only	1
Waterways	Lakes, swamps, rivers, ditches	2
Gaciofluvial	Sandy and/or gravel textures	3
Moraine Till	Variable soil texture, variable size range of stones sand and gravel clay and silt >1m to	4
Organic	Organic over clay	5
Lacustrine	Clayey to silty fine textured soils	5
Organic	Organic over gravel	7
Rock		8
Creeks and Streams	Clay bottom (generally <5m in width)	9

Coatings for Port Facilities

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America's dependency on international commerce can be realized by the tremendous continuous flow of very large volumes of fuel, perishables and manufactured goods that pass through our nations port facilities. The facilities have intense loading and unloading service requirements and schedules that are generally inflexible and intolerant of unscheduled maintenance. These port facilities rely on corrosion protection systems and coatings to minimize corrosion repair and are seeking advances in coating materials and application techniques to further extend the period between scheduled maintenance.

The workshop group on coatings for port facilities held discussions on present and desired practices to procure coating materials and to select proper application practices. Harbor and port facilities experience both wet and atmospheric corrosions, which often makes situations worse being in the splash zone or cyclic wet-dry areas. For this discussion, the type of coatings and practices were categorized as landside facilities and structures and water- and marine-based structures.

<u>The Important Issues for Landside Facilities and Structures were identified as:</u>

1. Need for better surface preparations, coating adhesion and long term wear protection for structures of near shore marine facilities exposed to salt spray. Ability/inability in obtaining non-conditional product installation and warranty for new work is a concern. Qualifying contractors involved in industry should have supported/accepted QA/QC standards such as SSPC's QP1 program, which needs to be expanded within the industry or established for their employees. SSPC is the Society for Protective Coatings.

2. Product performance criteria needs to be established and products need to be tested for compliance to establish a standard method of specifying quality products. By limiting choices to known quality products, this practice will enhance a contractor's ability to compete and bid on any coating application project, public or private. Establishing third party (non-government) standards to quantify performance and qualify products. Establishing methods to prevent falsifying or even "bending" the outcome of results. Promote advances in coating tests for better selection of coating materials

The Important Issues for Water Based Structures were identified as:

1. Steel sheet pile bulkheads and dock support structures...splash zone protection requirements as compared to normally submerged surfaces. Use of coal tar epoxies as a protective coating. What advancements are available for quick drying (setting up) coatings for application in the splash zone? Are there coatings that can be applied underwater? What are the proper surface preparation and coating application techniques for these conditions? Is there a need for robotics in the application of coatings? What would drive the initiation of robotics into the application of coatings?

2. Needs for adhesion and abrasive testing...proper methods and accuracy. What is the range of test results (paint viscosity, hardness, adhesion shear strength, adhesion tensile strength, coating flexibility on substrate, coating wear, etc) that is best for marine applications in a harbor setting? Develop an index based on tests to report the overall quality of the coating that can be used for quality control.

3. Product performance as compared to environmental "friendliness" of coating product needs to be established. The coating material and/or application technique that works best is not necessarily the most environmentally complaint. Where is the middle? What advancements are being made for better environmentally acceptable paint removal techniques?

4. What is the best approach to ensure that the proper coating materials are used with cathodic protection in the port facilities?

General Coating Issues Related to Port Facilities:

1. Can a port facilities user group be formed to compare performance of coating materials and coating application technologies? (Note to others: a marine and offshore focus group exists under SSPC and meets at the annual meeting. Issues include discussions of port facilities coating and corrosion control problems.)

2. Need to better prepare engineers during their university studies in the use of coating materials and their application technologies, specifically in corrosion and its mitigation. Need for more preparation in economic skills related to making engineering decisions.
3. Is the application of smart coatings with implanted sensors feasible in the near future for corrosion protective coating service in port facilities? Can coating integrity be assessed with a microwave (radar) gun for example, which can be pointed gun pointed at the smart coating?
4. Use of organic systems versus metallic systems. When is it proper to hot dip galvanize and when to paint? Is metallic coating becoming competitive with organic based coating for corrosion protection in port facilities. Need for a life cycle cost evaluation.
5. Promote advances in inspection methodologies of coatings on port facilities structures. What can be developed for monitoring the condition of coating during its service on a structure?
6. Promote advances in prediction of service life of coatings. What is the expected service life for land based coatings? What new coating materials and/or coating practices can make significant improvements in coating service life?

<u>Recommendations</u>

The working group on coatings for port facilities offers the following recommendations to the workshop report.

1. The development of performance based specifications (easier on owner).

2. The development of generally accepted design standards and practices for port authorities. This development may need to be geographically specific; such as blue water specific or brown water specific. These standards and practices need to beneficial to the owner.

3. Organize a working group, national or regional, to increase exchange of information on the performance of coating products and application methods to increase technological transfer of new coating materials and application methodologies into practice. The working group can formulate through user conscience new performance based specifications, design standards and practices for port facilities. There already exists the working structure for such a working group in the existing coating and corrosion societies. It needs an initiator. (Note: Loosely exists at SSPC).

Near 100 Percent Solids Tank Linings – Panacea or Pandemonium

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Introduction

Near 100% solids tank linings have been in existence for at least 40 years. These products are based on low molecular weight epoxy resins, which are liquid at room temperature. The reactants are also liquid at room temperature and range from straight amine compounds, such as diethyltriamine, to amine adducts. Since the resins are liquid at room temperature, less solvent is required in the formulation of the vehicle portion of the lining. This facilitates both manufacturing and application.

In general, lower molecular weight epoxide resins have decreased chemical resistance and are more brittle. Chemical resistance is not a major concern for ambient temperature salt-water exposures, albeit salt water is a highly corrosive media. To improve performance, higher molecular weight solid epoxy resins are added and co-reactant solvents such as benzyl alcohol compounds are added to reduce the "as manufactured," in the can, viscosity.

One early high solid (93%) lining formulation (circa 1960) was based on a ketamine reactant system. This material actually required atmospheric moisture to complete the final cure. As with MDA types of reactants, ketamines were determined to be carcinogenic and removed from the market.

The challenge in linings formulation has always been to balance worker safety, performance and environmental issues. Using current technology, several paint companies have met these challenges of meeting existing worker safety standards and environmental regulations. Performance evaluation is a work in progress.

Advantages

The obvious advantage of high solids tank linings is reduced solvent emissions. Reduced solvent emissions impact both worker safety and environmental restrictions. Worker safety is improved both by reductions of direct worker exposure to solvents during application and a reduced risk of fire or explosion due to concentrations of flammable air solvent mixtures.

Reduced solvent liberation to the atmosphere also provided a mechanism for the facility owners to meet strict environmental air quality standards. Where solvent capture technology is used; the efficiency of the device is improved along with reduced cost of operation.

Solvent is still required for cleanup of equipment. Waste reduction can also result, depending on the type of application equipment used.

Disadvantages

In general, higher solids materials have reduced pot life. To facilitate application, plural component application equipment is required. Since the "as manufactured" viscosity is increased, higher application pressures are also required, thus larger, more powerful high-pressure pumps. Both lead to procurement of higher priced equipment.

Materials are required to be packaged in standard volume ratios; preferably one to one mixes with the viscosities of each component matched as closely as possible. Heat is sometimes used to further reduce the "as applied" viscosity. Heating requires additional utilities. The thixotropy of the "as applied" product also has to accommodate edge build and retention.

Film thickness control requires a higher degree of applicator skill. There is a tendency to apply more material than is specified. Higher resultant film thicknesses increase consumption of lining materials, in excess of estimated quantities. Increasing the dry film thickness by an average of 2 mils for a 10 mil specified coating increases the lining consumption by 20 percent.

Higher solids linings are, in general, more expensive than lower solids materials on a dry mil per square foot basis, even when considering the increased solids content. Application equipment maintenance costs are increased due to both the increased complexity of the equipment, higher application pressures and, with some materials, increased equipment wear to due to the abrasive nature of the lining material on internal parts.

Because of the stiffness of high-pressure paint material supply lines, there is difficulty in applying linings to restricted access areas, such as behind stiffening and structure. The application equipment has a larger footprint, thus requiring more space for setup. The weight of the equipment is greater than conventional application equipment, which requires additional facility support.

Performance

Reports of performance have been mixed. The "grapevine" has reported improved performance, comparable performance, and in some cases miserable performance, when compared to standard, relatively low solids lining materials. Linings applied to static structures seem to do better than linings applied to structures subject to dynamic forces. One offshore semi submersible operator has reported ten plus years of excellent performance. One ship operator has reported cracking in the weld areas subject to dynamic structural flexing after a relatively short time period. The US Navy has reported good results.

In a recent National Shipbuilding Research Program test program investigating the retention of pre-construction primer (PCP) in ballast tanks, a lower solids tank lining performed as well as or better than the near 100% solids lining materials.

Cause and Effect

With the adaptation of high solids lining technology, the US Navy developed a process manual and special inspection requirements. Was this process control the reason for increased performance or was the use of the higher solids material the reason for improved performance? Does the formulation of so called edge retentive linings improve performance or is the stripe coating of welds and edges the real reason for improved performance? In conclusion, does the additional capital investment in material and equipment truly justify the use of higher solids materials?

Recommendations

1. Recommendation for investigation of developing a non destructive method of evaluating coating systems using thermography
2. Investigate the feasibility of using microwave technology as a method of surface preparation
3. Establish a welding procedure for welding on painted surfaces
4. Develop high solids products which meet VOC requirements that have less tendency to embrittle over time
5. Improve application equipment to facilitate applying high solids coatings in the field to inaccessible areas
6. Develop a mechanism to aid the painter in being able to achieve more uniform film thicknesses with high solids coatings in the field
7. Develop a certification and training program for painters in the marine industry
8. Help develop an engineering technologist degree / vocational training program for coating specification

9. Research program to develop coating systems that respond to exposure stresses
10. Develop a system that would be able to be used by the owner to detect corrosion or coating localized film degradation by utilizing electrical impedance
11. Determine the feasibility of adapting magnetic flux leakage technology as a method of determining metal loss in the shipping industry
12. Determine the feasibility of developing a hand held x-ray fluorescent system of detecting salts on the surface

Evaluating the Current State of Inspection practices for Protective Coatings (In Process and Continued Evaluation) and the Exploration of Opportunities for Improvement of these Practices

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Abstract

This “white paper” addresses an evaluation of the current state of inspection practices for protective coatings and the opportunities for improvement of these practices as determined by a panel discussion. Inspection is attributed as a tool to achieve the designed performance of an installed coating system through correct installation, thereby realizing the economic benefit of asset protection with protective coatings. Further, inspections are required to address maintenance and evaluate coatings performance. An evaluation of current testing methods and protocols, equipment and testing standards is explored with the intent of validation and/or improvement of these practices. The evaluation will explore both in-process inspection of new coating systems installation and in situ inspection of installed systems for maintenance (repair and life-cycle extension) and coatings system performance evaluation. The paper concludes with identification of Research & Design (R&D) issues determined from the panel discussion and a possible roadmap for achieving the presented opportunities for R&D of inspection technologies, protocols, practices, and management.

Introduction

The intended life cycle of a protective coating (paint) system presents the engineered economic value of that coating system by providing protection from corrosion to that asset. The protection of that asset is typically a requirement of economic, operational, environmental, and safety issues.

Inspection during protective coatings installation is employed as a tool to ensure that the installation of the coating is within the design parameters of the engineered and specified coating system. The emphasis of industry endeavor in the form of practices, standards, and training has been primarily directed to this mission.

Recognizing that deficiencies in the original installation do occur, further inspections are required to initiate repair efforts, monitor coatings system performance, and maximize the life cycle of the installed coatings. These in situ inspections may present greater challenges in providing concise data to make sound engineering decisions about refurbishment issues such as maintenance and over-coating (applying additional coatings to an already installed system for life-cycle extension). The information gathered in the in-service inspections, utilized with sound management practice is a valuable tool to achieve the intended economic value of the installed coatings system.

For discussion the two most common types of inspections concerning protective coatings can be classified as:

1. In-process inspections conducted during the initial installation of the coatings systems and any repair efforts to that initially installed coating before entry into service.
2. In-service inspections of the installed coatings system at regular intervals for evaluation and scheduling of repairs to the installed system, including evaluation of the installed coating film for repair, refreshment (over-coating) and complete replacement.

In-Process Inspection

To evaluate only the inspection process it is assumed that the coatings materials are properly formulated, manufactured correctly, and have been correctly specified for the intended service. The emphasis of in-process inspection is to ensure the correct application of that specified coatings system and the verification that the installation is as specified.

A brief summary of the elements of typical in-process inspections for coatings application include the following:

1. Preexisting Conditions
   a. Surface Contaminates (Visible and Non-Visible)
   b. Fabrication and Design Defects/Issues
2. Surface Preparation
   a. Anchor Profile
   b. Level of Surface Cleanliness
   c. Non-Visible Contaminates
   d. Environmental Condition
   e. Special Substrates
      i. Concrete
      ii. Stainless Steel
      iii. Others

3. Coatings Application
    a. Materials Verification
    b. Mixing and Thinning
    c. Application
    d. Environmental Conditions
    e. Post Application
        i. Dry Film Thickness (DFT) Measurement
        ii. Film Continuity Evaluation (visual or holiday testing)
4. Documentation and Reporting Systems
    a. Hard Copy Systems
    b. Computer Based Reporting
    c. Auditing/Verification of Documentation
5. Other Requirements

Current industry standards address many of the described elements. However, new surface preparation and application technologies, and continued discoveries as to the cause of premature coatings failures require continued reevaluation of existing standards and promulgation of new standards as required.

Evaluating the aspects of in-process inspection, opportunities for research and development emerge from the following questions.

Do the current standards adequately address the required testing? Are additional standards required? If so, what are those standards?

Immediate industry demand for standards pertaining to visible and non-visible levels of contamination are evident. The following ISO Standards are currently available with regards to testing procedures:

- *ISO 8502-5:1998 Preparation of Steel Substrates Before Application of Paints and Related Products—Tests for the Assessment of Surface Cleanliness—Part 5: Measurement of Chloride on Steel Substrates Prepared for painting—Ion Detection Tube Method*

- *ISO 8502-6:1998 Preparation of Steel Substrates Before Application of Paints and Related Products—Tests for the Assessment of Surface Cleanliness—Part 6: Extraction of soluble contaminates for analysis – The Bresle method*

- *ISO 8502-9:1998 Preparation of Steel Substrates Before Application of Paints and Related Products—Tests for the Assessment of Surface Cleanliness—Part 9: Field method for the conductometric determination of water soluble salts*

- *ISO 8502-10:1999 Preparation of Steel Substrates Before Application of Paints and Related Products—Tests for the Assessment of Surface*

Cleanliness—Part 10: Field method for the titrimetric determination of water-soluble chloride

- *ISO 8502-12:2003 Preparation of Steel Substrates Before Application of Paints and Related Products—Tests for the Assessment of Surface Cleanliness—Part 12: Field method for the titrimetric determination of water-soluble ferrous ions*

Efforts for development of standards for evaluation of non-visible surface contamination by SSPC: The Society for Protective Coatings and NACE International (*Task Group 259 – Salt Contaminants, Nonvisible, Soluble on Coated and Uncoated Metallic Surfaces Immediately Prior to Coating Application: Evaluation*) continue, although expected dates of any publication are not available. Quantifying the allowable values of non-visible contamination as determined by these described testing methods to ensure the coating application is unaffected and no detriment to performance is experienced is the current challenge facing industry.

Assessment of visible contaminates (dust) can be addressed with ISO Standard *ISO 8502-3:1992 Preparation of Steel Substrates Before Application of Paints and Related Products—Tests for the Assessment of Surface Cleanliness—Part 3: Assessment of Dust on Steel Surfaces Prepared for painting (Pressure Sensitive tape Method)* using clear tape and assessing the visible residue adhering to the tape.

Further opportunity exists for the development of Secondary Surface Preparation Criteria/Standards (example: exceeding the recoat window of an epoxy - Methodology for evaluation). Currently, surface preparation standards exist for the preparation of surfaces and address the cleanliness requirements of that substrate, typically steel. Current surface preparation standards do not address the preparation requirements of painted surfaces to receive additional coatings application and focus more directly on the substrate itself.

Is the current array of testing equipment adequate? What new equipment could be developed to assist? The development of new testing equipment by equipment manufacturers is typically driven by industry requirements with potential market for the return of development costs and potential profit. The potential of wide scale use is characteristically a requirement to initiate new testing equipment development after identification of the specific need.

Currently, improvements for instrumentation used in in-process inspection may be found in surface moisture detection, anchor profile peak densities and improvement in the dry film thickness evaluation of coatings applied over concrete present immediate opportunities for improvement of process and equipment.

What is the measurable contribution (value) of inspection to the success (achieving designed life-cycle) of a protective coatings installation? Research executed to quantify the “value” of in-process coatings inspection to the extension and/or realization of expected life cycle performance of the installed system would provide rationale to management for the additional cost of in-process inspection during coatings application. Although most agree that the inclusion of inspection in coatings projects results in properly executed application and a subsequently longer life cycle before repairs, there is little industry data for examination to support this conclusion. Previous publication of this subject has typically presented a comparative view of a project without in-process inspection that failed prematurely and the costs associated with that failure compared to the additional cost of inspection with the assumption of project success (expected design life-cycle).

What is the required effort of inspection for it to be realized as an effective contribution to project success? Is coating inspection performed at designated “hold-points” an effective tool? Can “part-time” inspection be considered a worthwhile investment in the success of a coatings project? What training and/or certification and level of experience should be required for inspectors and firms providing inspection?

Standards/Recommended Practices for Implementation of Inspection for Protective Coatings Projects would provide guidance to achieve the expected life-cycle performance of the installed coating system though in-process inspection would ensure consistent application of in-service inspection services determined to provide effective contribution to the coatings installation project. Consistent practices with regards the to level of effort, inspection practices, and project documentation should be addressed in the proposed standard.

Has the profession of Coatings Inspector evolved to a level requiring a professional association to ensure adequate communication of new technologies and provide a catalyst for the improvement of the profession?

In Service Inspection

Continued inspections of the installed coating systems are utilized to evaluate the performance of those systems and to determine maintenance efforts and ensure that the repair and/or rehabilitation course of action taken will be successful. These inspections typically address the following:

1. Dry Film Thickness
2. Coating Adhesion
3. Substrate Condition
4. Coating Film Integrity
5. Service Environment

Interpretation of collected data is performed to typically provide the most economically feasible course of action. Standardizing the evaluation criteria for the three basic actions available to us: spot repair, overcoat (a decisive evaluation of the system's ability to accept repair and overcoat is required) or replacement should lead to consistent interpretation and economically viable asset protection success. The following questions and opportunities emerge:

Are we presently looking at the right metrics in terms of in-service inspection and repair? Are we looking at any metrics currently? Are industries so disparate in requirements that common processes become impossible?

Can the equipment and protocols used for in-process inspection be used during in-service inspection? Do we have the proper inspection tools and protocols to efficiently evaluate condition during service and the ability to forecast remaining service life? Life cycle expectations of coatings systems are typically predicted from laboratory analysis prior to installation and not from an evaluation of the in situ coating. Is there a need to develop tools focused on in-service inspection? Possibilities include:

- Coatings age and degradation
- Ability to apply over-coatings
- Coatings deterioration and remaining service life

Except for items such as chalking, few tools exist for NDE of in-service coatings. Identified prospects will have to eventually have some standard associated with them. Additional opportunities may exist with:

- Electromagnetic (EM) methods-spectroscopy, use of IR, UV, color fading, etc.
- "Smart" primers (formulated to give some indication of nascent corrosion)
- Wet and dry adhesion testing (can we accomplish nondestructively?)
- Degree of cross-linking
- Detection of the products of deterioration
- Blister/blister fluid analysis
- Visual indication
- Water or other "solvent" uptake by coating film
- Exudation of high boiling volatiles?

Continued research of Electrochemical Impedance Spectroscopy (EIS) and its use as a field measurement tool for coatings performance may provide tools for the field measurement of remaining coatings life. The permeability of the installed coating and evaluation of substrate corrosion not yet visually apparent may be obtained from this testing. Currently used for laboratory evaluation of coatings, development of field instrumentation and the associated metrics may provide reliable tools for coatings condition assessment.

Do current training programs adequately address the practices required for evaluation of in situ coatings? Current Inspector training programs focus on in-process inspection. Although providing instruction in the use of equipment also utilized for in-service (dry film thickness evaluation, adhesion, and etc.) the specifics of evaluating coatings for the development of remedial and/or maintenance planning is not addressed. The opportunity for development and presentation of training addressing the specifics of in-service coatings evaluation is apparent.

Do we have confidence in the various determinations of the causes of pre-mature failure being promulgated (are there standardized methods of examination, analysis and reporting)?

Do we have standards to evaluate condition of in-service coatings? Can our description of condition be consistently quantified? The development of Guidelines/Practices/Standards for evaluating In-Service Coatings could provide industry with consistent metrics of evaluation for coatings service life through a uniform approach to evaluation.

Is there a management system to store, manipulate, interpret, distribute, and use the data we gather? Are there standards controlling this data collection? Standardized Methodology for Data Collection and Management would provide:

- Consistently Quantified Condition
- Industry Shared Information

Do we have procedures available to us to make sound maintenance decisions (i.e., successful, cost effective ones)? Can we translate the existing condition, together with expected useful service life, into budgetary requirements? Are there criteria for determining the most cost effective maintenance effort?

Determining analytical procedures for coating life predictions will require the following developments and practices:

- Standard degradation models (statistically based)
- Metrics required
- NDE to gather data
- Service to laboratory correlations (atmospheric versus immersion for example)
- New procedures to evaluate service life of new coating formulations
- In-situ evaluation
- Accelerated testing procedures

The repairs applied to new coatings and linings installations have an effect on the system performance and its expected life-cycle and maintenance requirements. The selection of repair methods that maintain the expected life cycle of the

installed systems are paramount. How are these decisions currently made? Opportunities for the research and development exist within the following:

- Quantification of the effect of "repairs" on newly installed coatings system's life-cycle performance
- Quantification of Performance & Repair Criteria for

Summary

Although many questions regarding coatings inspection (both in-process and in-service) have been presented, the surfacing opportunities appear to rest with the further development of the inspection processes of in-service coatings. The panel consensus for opportunities for the improvement of process, practices, research, and development have focused within the following areas:

- A Study of the Measurable Economic Contribution of Inspection to Coatings Project Success and Performance

- Standards/Recommended Practices for Implementation of Inspection for Protective Coatings Projects

- Professional Organization of Coating Inspectors

- Secondary Surface Preparation Criteria/Standards (example: exceeding the recoat window of an epoxy - Methodology for evaluation)

- Guidelines/Practices/Standards for evaluating In-Service Coatings and the training of Coating Survey Inspectors, with focus on Inspection and Evaluation of In-Service Coatings and tools for evaluation.

- Criteria for determining the most cost effective maintenance effort and tools to quantify:
    - Coatings age and degradation
    - Ability to apply over-coatings
    - Consistent evaluation

- Quantify the effect of "repairs" on newly installed coatings system's performance

- Standards for Quantification of Performance & Repair Criteria

- Standardized Methodology for Data Collection and Management
    - Consistently Quantified Condition
    - Industry Shared Information

Formulation of the roadmap for research and/or development of these initiatives will fall to industry organizations such as NACE International and SSPC: The Society for Protective Coatings as well as government research agencies funding industry research.

The development of standards and recommended practices, after identification of the specific requirements, is within the mission of industry organizations and the framework currently exists for their development. Communication of these requirements to the organizations is the first step to development.

Research and further study of the issues regarding predictability of in-service coatings and linings systems and the value of in-process inspection will require funding and sponsorship from government and industry. The economic benefit of extended life cycle performance (from both successful application and sound maintenance decisions) provides the initiative for funding and warrants the effort required.

This working group has attempted to identify and clarify the current issues regarding “Inspection & Repair” within industries using protective coatings for asset protection to improve the inspection and repair process. The next steps include industry and coatings organization support to fund and develop the suggestions made within this paper. The operational, environmental, safety, and economic benefits derived from the improvement of the process justify immediate effort.

Recommendations from the Discussion Groups

Programs
Programs consist of numerous projects, which must be completed to achieve the intended goal.

Research

1. Quantitative evaluation of the long-term field performance of pipeline coatings. One project should install coated pipe samples in the field at carefully selected locations representative of different environmental conditions. Several monitoring methods should be used. In addition, the coating performance evaluation should include both consistent and fluctuating temperatures with transient and cyclic temperature fluctuations. A one-day scoping meeting prior to this investigation should be held with good representation of the interested parties.

2. Development of practices for evaluating pipeline coatings for service under extreme conditions such as: Offshore-deep sea, Offshore-Arctic, Onshore-equator is recommended. These investigations should include three types of coatings: Anti-corrosion coatings, Abrasion-resistant coatings, and Insulation coatings.

3. Development of a non-destructive method of evaluating the application of coating systems. Programs need to explore the feasibility of thermography, magnetic flux leakage, electrical impedance, and eddy current phase array. Modeling using EIS is not reliable.

4. Development of specific advancements in coating materials. A project for non-skid deck coating systems that will last when applied over less than perfect surface preparations. Parameters that control coating performance. Modeling of performance of all coatings (not only FBE). A project should include the evaluation of coatings at higher temperature in the laboratory. Performance of insulation coating should be investigated. Research project to develop coating systems that respond to exposure stresses needs to be performed.

Development

5. Improvement in the effective use of coatings for port facilities and the development of the necessary performance-based specifications. The development of generally accepted design standards and practices for port authorities needs to be established. These standards and practices need to be beneficial to the owner. Also the program needs to develop generally accepted design standards and acceptances for port facilities. This development may need to be geographically specific such as: blue water specific or brown water specific.

6. Advanced methodologies for applications of coatings. A project needs to address paint application issues without the use of brushes and rollers to increase productivity, lower costs, and less personnel exposure. The proposed investigation should include concerns of issues such as: curing time compared to burial or immersion time and adhesion of field-applied coatings to mill-applied coatings. An investigation to assess the effects of stockpiling of coating products on pipeline coatings performance including the effect of temperature, ultra-violet light, and time needs to be established. Development of high solid products, which meet VOC requirements that have less tendency to embrittle over time. Develop a mechanism to aid the painter in being able to achieve more uniform film thicknesses with high solid coatings in the field. The use of a capture device at the spray gun versus total encapsulation of the space to be painted should be investigated. Evaluate the need to increase the investment in coating application technology R&D. Establishment of a welding procedure for welding on painted surfaces is recommended.

7. Assessment of new technologies for surface preparation before coating. This program should include projects on the feasibility of using microwave technology for surface preparation, hand-held x-ray fluorescence system to detect salts on the surface, and a project to improve the dissemination and clarity of information on allowable surface chlorides. Improvement of application equipment to facilitate applying high solid coatings in the field to inaccessible areas. A project investigating the effects of minor variations in surface preparation and effects of variation in composition of surface contamination, including mill scale, on long-term coatings performance is necessary. A project on secondary surface preparation critera / Standards (example: exceeding the recoat window of an epoxy- Methodology for evaluation) needs to be established. The cost of surface preparation and coating application for underwater hull areas is going up and the designs of coating technology for this area has not kept pace.

Administration

8. Standardized methodology for data collection and management. An unbiased third party to compile an industry wide historical data base on pipeline coating performance and evaluate the data critically needs to be established and funded. A program to establish user-friendly standardization needs to be initiated and performed. The program would include a project on the standard/ recommended practices for implementation of inspection for protective coatings projects.

9. Formulation of a roadmap for coatings research and/or development that indicates the proper sequence of projects. The roadmap needs to be periodically updated by industrial organizations as well as government research agencies and industrial users of coated structures. Such a roadmap would be helpful in prioritizing national and international needs and to assist in obtaining the necessary funding. The roadmap program will need to be annually updated by NACE International and SSPC (The Society for Protective Coatings).

10. A working group, national or regional, to increase exchange of information on the performance of coating products and application. The working group can formulate through user conscience new performance based specifications, design standards, and practices for port facilities. There already exists the working structure for such a working group in the existing coating and corrosion societies. It needs an initiator. (Note: Loosely exists at SSPC).

11. Evaluation of the economic issues of coating materials, their application, and their service behavior. A specific project on the study of the measurable economic contribution of the inspection of coatings project successes and performance needs to be performed. A project to study economics of coating technology to suggest and recommend the most cost effective use of the present technology should be implemented. The issue is that use and deployment of new coating technology is hampered by high cost of new equipment. Look into what can be done to utilize existing equipment; lower the cost of new equipment; or provide the financial incentives needed. Consumer and coating industry feedback loop needs to be improved. Problems are generally reported and investigated; however, successful applications rarely are investigated to confirm good practice.

Operations

12. Advanced methods for coating repair. This program should include a project on standards for quantification of performance and repair criteria and a project to quantify the effect of "repairs" on newly installed coatings system's performance.

13. Training, education, and certification of painters, corrosion engineers, and inspectors in the marine and pipeline industry. Develop a certification and training program for painters in the marine industry. Help develop an engineering technologist degree / vocational training program for coating specification. Guidelines/Practices/Standards for evaluating In-Service Coatings and the training of Coating Survey Inspectors, with focus on Inspection and Evaluation of In-Service Coatings and tools for evaluation needs to be organized. A special program for educating Coast Guard and MMS inspectors to establish consistency with the offshore industrial standards. Development of a hiring program offering training and certification plus weekly pay, which would have an impact on safety, employee morale, and salary.

14. Development of coating/corrosion assessment criteria and acceptable corrosion levels for use by corrosion engineers and regulators in the development and assessment of Asset Integrity Management Programs. Development of a criteria for determining the most cost effective maintenance effort and tools to quantify: coatings age and degradation, ability to apply over-coatings, and consistent evaluation needs to be established.

15. Address the environmental and health and safety issues regarding paint materials and their application. A project for the determination of the effects of environmental conditions and variations in coating procedures on the performance of field-applied pipeline coatings needs to be instituted. A project on the development and research of environment tolerant coatings that can be used year round with increased quality. The development of pipeline coatings with anti-microbial properties. This development must achieve coating acceptable ecological concerns.

Section 5

Special Lectures

NAVSEA
NAVAL SEA SYSTEMS COMMAND

COATINGS FOR U. S. NAVY SHIPS DEVELOPMENTS AND STATUS

By A.I. KAZNOFF

SEA 05M1, April 2003

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Outline

I. HISTORY 1982 - 1989

II. ENVIRONMENTAL IMPACTS – FEDERAL AND STATE

III. POST COLD WAR EFFECTS

IV. CHANGE TO WORLD BEST PRACTICE 1994

V. RELIABILITY, ENVIRONMENT AND UNDS

VI. TECHNOLOGICAL STATUS AND NEEDS

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HISTORY - 1982 – 1989

• USE OF NAVY (MILITARY/FEDERAL) SPECIFICATIONS

• NUMBER OF SPECIFICATIONS – ABOUT 75 IN THE 1980'S AND 14 NOW

• USE OF KEY NAVY FORMULA SPECIFICATIONS – EG. USE OF "MARE ISLAND" EPOXY AS THE REFERENCE ANTI-CORROSIVE PAINT AND VINYL ANTI-FOULING (AF) WITH CUPROUS OXIDE

• TYPES OF PAINTS USED

- ➢ EPOXIES FOR ANTI-CORROSIVE PAINTS
- ➢ SILICONE ALKYDS FOR TOPSIDE EXTERIOR PAINTS
- ➢ CHLORINATED ALKYDS FOR INTERIOR PAINTS
- ➢ VINYL AF PAINTS AND SOME COMMERCIAL AF PAINTS
- ➢ EPOXY BASED NON-SKID PAINTS

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HISTORY - 1982 - 1989 (Cont.)

• WHERE NAVY PAINTS WERE USED

- ➢ NAVAL SHIPYARDS (MAINTENANCE ONLY) – 8 YARDS
- ➢ PRIVATE SHIPYARDS (NEW BUILDING AND MAINTENANCE) – 10+ YARDS

• DOCKING CYCLE TREND WAS 5+ YEARS

• SIZE OF THE NAVY WAS PROJECTED TO BE 500+ SHIPS

• LOW OPERATIONAL CYCLE – SHIPS IN PORT FOR 50% OF THE TIME

• OPERATIONS WERE WORLD WIDE

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HISTORY - 1982 – 1989 (Cont.) Major Changes and Developments

• DELIBERATE SHIFT TO COMMERCIAL COATINGS THROUGH THE USE OF PERFORMANCE SPECIFICATIONS AND QUALIFIED PRODUCTS LISTS (QPL)

• DELIBERATE ELIMINATION OF HAZARDOUS/TOXIC PAINT INGREDIENTS SUCH AS LEAD (DRIERS AND PIGMENTS) ASBESTOS, CRYSTALLINE SILICA AND CHROMATES

• MAJOR PROBLEMS IN ANTI-FOULING PAINT
  - PERFORMANCE WAS LIMITED TO 18 MONTHS WITH THE VINYL AF PAINT
  - MAIN ACTIVITY WAS NAVY R&D IN TRIBUTYL TIN (TBT) PAINTS
  - EVALUATION OF COMMERCIAL TBT PAINTS

• PARALLEL EFFORT WAS SPENT IN QUALIFYING ALTERNATIVE CUPROUS OXIDE AF PAINTS BECAUSE TBT USE WAS UNCERTAIN DUE TO LACK OF ENVIRONMENTAL ASSESSMENT

• DEVELOPMENT AND QUALIFICATION OF WATER-BORNE INTERIOR AND EXTERIOR PAINTS

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ENVIRONMENTAL IMPACTS – FEDERAL/STATE REGULATIONS

- FEDERAL (EPA) AND SOME STATE AUTHORITIES REQUIRE REGISTRATION OF PAINTS USED ESPECIALLY ANTI-FOULING PAINTS BECAUSE OF THE BIOCIDE USED

- THE LATE 80'S WAS A PERIOD OF HOPE OF OBTAINING A MORE EFFECTIVE AF PAINT BASED ON TBT

- THE EPA AND THE MAJORITY OF AFFECTED STATES DID NOT ACCEPT THE NAVY ENVIRONMENTAL ASSESSMENT FAVORING ITS USE

- FEDERAL REGULATIONS SET THE LIMIT OF EMISSIONS AT 4 MICROGRAMS PER SQUARE CENTIMETER PER DAY FOR TBT

- STATE CHALLENGES TO NAVY USE OF TBT PAINTS BASED ON TIGHT LOCAL WATER QUALITY STANDARDS AND LOCAL FEARS OF TBT

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ENVIRONMENTAL IMPACTS – FEDERAL/STATE REGULATIONS (Cont.)

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- NAVY DECIDES NOT TO USE TBT PAINTS AND SWITCHES TO TWO COMMERCIAL ABLATIVE PAINTS BASED ON CUPROUS OXIDE

- LOSS OF TBT OPTION FOR ALUMINUM HULLS POSES MAJOR PROBLEMS (AS COPPER BASED AF PAINTS ARE UNSUITABLE) – PROBLEM SOLVED BY THE INTRODUCTION OF "EASY RELEASE" SILICONE PAINT

- NET RESULT WAS THAT THE NAVY WAS UNAFFECTED BY THE IMO BAN ON TBT PAINTS WHICH CAME MORE THAN A DECADE AFTER THE NAVY DECISION NOT TO USE TBT AF PAINTS

- NAVY CANCELLED THEIR MILITARY SPECIFCATION FOR ORGANOTIN PAINTS (MIL-P-24588) IN 1985

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ENVIRONMENTAL IMPACTS – FEDERAL/STATE REGULATIONS (Cont.)

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- LATE EIGHTIES WAS A PERIOD WHEN THE STATE OF CALIFORNIA PUSHED THROUGH REGULATIONS FOR LIMITING VOLATILE ORGANIC COMPOUND (VOC) CONTENT

- BY 1989 THE NAVY ESTABLISHED BY NEGOTIATION THE LIMITS FOR IMPLEMENTATION BY SEPTEMBER OF 1991 THE GENERIC NEW VOC LIMIT OF 340 GRAMS OF SOLVENT PER LITER OF PAINT (g/L)

- THE NAVY MET ALL VOC REGULATIONS THROUGH REFORMULATION PROGRAMS BY THE DEADLINE DATE EXCEPT FOR ONE PAINT WHICH WAS COMPLETED BY JANUARY 1992

- IN 1992 THE FEDERAL"NATIONAL EMISSIONS STANDARDS FOR HAZARDOUS AIR POLLUTANTS" (NESHAP) HIT THE NAVY

- RESULT WAS REGULATION IN 1997 WHICH WAS MET BY THE NAVY. IN LARGE MEASURE THE NESHAP WAS BASED ON VOC LIMITS SET BY CALIFORNIA

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POST COLD WAR EFFECTS ON NAVY

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- REDUCTION OF FLEET SIZE TO LESS THAN 300 SHIPS CURRENTLY
- REDUCTION IN MAINTENANCE BUDGETS
- REDUCTION IN SHIPYARDS & FACILITIES (8 SHIPYARDS TO 4)
- EXTENSION OF DOCKING CYCLES TO 10+ YEARS
- REDUCTION IN PERSONNEL RESULTING IN LOSS OF EXPERIENCED PEOPLE
- PERIODIC DIFFICULTIES IN RECRUITMENT AND RETENTION OF NAVY PERSONNEL
- FLEET MATERIAL OFFICERS DEMANDING MORE RELIABLE LONGER LASTING COATINGS IN ALL CATEGORIES – 1994 – BUT NO FUNDING TO DEVELOP.
- ACCEPTANCE OF "REASONABLE RISKS"

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CHANGE TO WORLD BEST PRACTICE 1994

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- BETWEEN 1994 AND 2002 13 SHIPBUILDING YARDS WERE VISITED BY NAVSEA IN EUROPE, JAPAN AND KOREA
- HIGH PERFORMANCE PAINTS AND APPLICATION REQUIREMENTS ESTABLISHED BY INTERACTIONS WITH WORLD PAINT SUPPLIERS – SIGMA, AKZO-NOBEL, HEMPEL, JOTUN, CHUGOKU
- VERIFICATION OF COATING PRACTICE WITH CLASSIFICATION SOCIETIES SUCH AS DET NORSKE VERITAS
- EXAMINATION OF NAVY DATA SHOWED;
  - LIFETIME OF A BALLAST TANK COATING VARIED FROM 1 YEAR TO 10 YEARS WITH THE SAME PAINT (AVERGAGE LIFE LESS THAN 5 YEARS)
  - QC & QA ON COATINGS SYSTEMS WAS HIGHLY VARIABLE
  - LACK OF DIRECTION FOR ROUNDING CORNERS LED TO GENERIC EARLY FAILURES IN TANKS.
  - TRAINING OF APPICATOR PERSONNEL WAS/IS QUESTIONABLE

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CHANGE TO WORLD BEST PRACTICE 1994 (Cont.)

- ACTIONS TAKEN
  - ➢ PROCESS CONTROLS BY QUALITY CONTROL - AT LEAST TWELVE INSPECTIONS OR "CHECK POINTS" ARE REQUIRED BY TANK COATING PRESERVATION PROCESS INSTRUCTION (PPI)
  - ➢ EMPHASIS ON PROPER SURFACE PREPARATION AND SOLUBLE SALT CONTROL
  - ➢ DEVELOPMENT OF EDGE RETENTIVE PAINTS – SIGMA
  - ➢ INTRODUCTION OF "SOLVENT-FREE" PAINTS (EPOXIES)
  - ➢ INTRODUCTION OF PLURAL COMPONENT EQUIPMENT – NAVAL SHIPYARDS AND PRIVATE SHIPYARDS
- NEW EXPECTATIONS (EXAMPLES)
  - ➢ BALLAST TANKS, COMPENSATED FUEL/BALLAST TANKS, FUEL TANKS: NEW EXPECTEDS SERVICE TO 20+ YEARS; OLD SERVICE LIFE WAS 5 YEARS.

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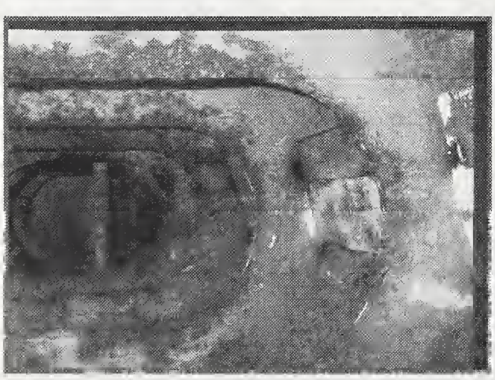
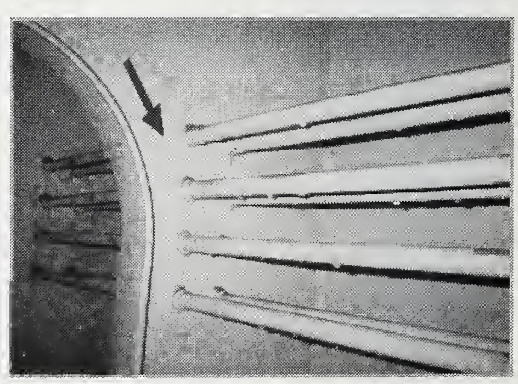
Experience



USS Ogden <u>old technology</u> tank coatings after 3years



USS Ogden <u>new technology</u> tank coatings after 6 years

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RELIABILITY, ENVIRONMENT, EPA CONSTRAINTS AND UNDS

RELIABILITY

• RELIABILITY DEPENDS ON PROCESSES THAT ARE VERIFIED FOR THE CONDITIONS ENCOUNTERED ACCOMPANIED BY QUALITY CONTROL WITH INDEPENDENT OVERSIGHT

• INTERNAL SPACES ON SHIPS ARE EASIER TO CONTROL FROM AN ENVIRONMENTAL STANDPOINT WITH EQUIPMENT THAT MAINTAINS REQUIRED TEMPERATURE AND HUMIDITY.

• SPECIFICATIONS WITH TEMPERATURE AND HUMIDITY CONTROLS CAN HAVE VERY LOW RECORDS OF COMPLIANCE WITHOUT AUTOMATIC CONTROL DEVICES.

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RELIABILITY (Cont'd)

• EXTERIORS OF SHIPS ARE CONSIDERABLY HARDER TO PRESERVE BECAUSE NEARLY ALL EXTERIOR PAINTING IS DONE IN THE WEATHER WITHOUT THE BENEFIT OF TEMPORARY SHELTER AND CONTROLS.

• VAGARIES OF WEATHER ALSO INTRODUCE SERIOUS RISKS IN ACCOMPLISHMENT OF QUALITY WORK AND REQUIRE EXPENSIVE REWORK AS A RESULT OF WEATHER UPSETS.

• THE ABILITY TO DECREASE THE RISKS OF WEATHER INDUCED "FAILURES" OF PAINTING MAY BE ACCOMPLISHED BY THE FOLLOWING MEANS:

- ➢ RAPID CURE PAINT SYSTEMS TO DECREASE THE PERIOD OF SUSCEPTABILITY TO WEATHER UPSETS AND SAVE MONEY (THIS MAY BE THE BETTER OPTION IF SHELTER OPTION IS OUT)
- ➢ DEVELOPMENT OF PAINT TOLERANT TO MOISTURE (THIS IS AT BEST A MARGINAL IMPROVEMENT)
- ➢ UTILIZATION OF TEMPORARY OR PERMANENT ENCLOSURES . THIS REQUIRES BUSINESS CASE STUDIES. (BEST CORRECTIVE OPTION FOR MEETING UNIFORM SCHEDULES)

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EPA CONSTRAINTS

• TRENDS IN CALIFORNIA INDICATE THAT VOC (NESHAP) VALUES ARE RAPIDLY DECREASING

1991 - 340 g/L
2004 - 250 g/L
2006 - 100-150 g/L

THE TREND IS APPROACHING ZERO VOC

• WATER QUALITY ISSUES EVIDENT IN SAN DIEGO (BAY AREA) WHERE HIGH COPPER LEVELS ARE SEEN (I.E. IN PLEASURE CRAFT HARBORS)

• FEDERAL EPA HAS RECENTLY PROPOSED MORE STRINGENT LIMITS ON COPPER LEVELS. THIS HAS A MAJOR IMPACT ON COPPER USE IN ANTI-FOULING PAINTS. SOME EUROPEAN COUNTRIES AND CANADA HAVE CONSTRAINTS ON COPPER IN THE WATER

• DUE TO ACTIONS IN THE MID-NINETIES, THE NAVY HAS EPOXIES (ANTI-CORROSIVES AND OTHER USES) THAT WILL MEET ALL KNOWN CALIFORNIA LIMITS .

• IT IS DOUBTFUL IF ALKYD LIMITS BELOW 200g/L ARE ACHIEVABLE

• ANTI-FOULING PAINTS, DUE TO RESINS USED, ARE UNLIKELY TO GO BELOW 400 g/L (WITH SOME RARE EXCEPTIONS TO 340 g/L)

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UNIFORM NATIONAL DISCHARGE STANDARDS (UNDS)

• JOINT EPA – DOD (AND COAST GUARD) EFFORT TO DEVELOP STANDARDS FOR DISCHARGES FROM SHIPS INTO THE WATER (WITHIN THE 12 NAUTICAL MILE LIMIT)

• APPLICABLE TO 25 SHIP DISCHARGES, BUT FOR THIS PRESENTATION, THE SPECIFIC DISCHARGE IS “SHIP HULL LEACHATE” DISCHARGE BECAUSE OF ITS CONTRIBUTION TO COPPER CONTENT IN HARBORS SUCH AS SAN DIEGO

• TO DATE, NO STANDARD HAS BEEN DEVELOPED OR EXISTS

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TECHNOLOGICAL STATUS AND NEEDS

• THE NEEDS AND DILEMMAS HAVE BEEN PRESENTED AND WHILE SOME ARE IMPORTANT PRESENT DIFFICULTIES, THERE ARE SIGNIFICANT OPTIONS AND DEVELOPMENTS FOR FUTURE SOLUTIONS.

• TOPSIDE ALKYD PAINT CAN BE REPLACED WITH SOLVENT-FREE ALIPHATIC URETHANES. THE PROBLEMS WITH THIS CHANGE ARE:

- ➢ USE OF PLURAL COMPONENT APPLICATION FOR SHIPS FORCE MAINTENANCE IS UNLIKELY
- ➢ PROBLEMS WITH OVERCOAT ADHESION - NEED FOR FUNCTIONALITY IN THE RESIN TO OVERCOME LIMITATIONS

• CHANGE TO URETHANE (OR POLYUREA) FOR RAPID CURE/REPAIR STRATEGY FOR ALL SYSTEMS. FURTHER ADVANTAGE IS WIDENING OF THE RANGE OF APPLICATION TO LOWER TEMPERATURES (320 F)

• ANTI-FOULING PAINTS HAVE MAJOR PROBLEMS FOR MEETING THE 340-400 g/L VOC LIMIT AND HIGH SOLVENT CONTENT BRINGS PROBLEMS FOR LONG SERVICE AF PAINTS DUE TO SLOW SOLVENT EVAPORATION AND RESULTING LOW MECHANICAL STRENGTH OF THE PAINT.

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TECHNOLOGICAL STATUS AND NEEDS (Cont.)

• THE SOLUTION IS THE DEVELOPMENT OF A TWO-COMPONENT PAINT SYSTEM THAT PROVIDES THE PROPER SELF-POLISHING FOR THE BIOCIDES USED.

• WHY ARE WE OPTIMISTIC? R & D AT THE NAVAL RESEARCH LABORATORY (NRL) LED BY Dr. JEF VERBORGT HAS IDENTIFIED THE NEEDED TECHNOLOGY OF:

- ➢ RAPID CURE POLYURETHANES
- ➢ HIGH FUNCTIONALITY SYSTEMS THAT ALLOW HIGH ADHESION OF OVERCOAT/REPAIR
- ➢ AF SELF-POLISHING SYSTEMS HAVE BEEN IDENTIFIED

• THE POSITION OF THE U. S. NAVY IS THAT THE TECHNOLOGY DEVELOPED BY NRL/ JEF VERBORGT CAN BE MADE AVAILABLE TO THE COATINGS INDUSTRY. PATENT APPLICATION HAS BEEN MADE AND OTHERS WILL FOLLOW.

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For More Information:

• NAVAL RESEARCH POINT OF CONTACT IS MR. KEITH LUCAS, NRL, CODE 6130, CENTER FOR CORROSION SCIENCE AND ENGINEERING, PHONE NUMBER 202-767-0833.

• FOR FURTHER REFERENCE ON THE TOPIC OF RAPID CURE RESIN SYSTEMS SEE NATIONAL ASSOCIATION OF CORROSION ENGINEERS (NACE) PUBLICATION "MATERIALS PERFORMANCE" OCTOBER 2003.

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Backup Slides – Recent Developments in Navy Coatings

• HIGH SOLIDS EDGE RETENTIVE COATINGS

TANKS AND EXTERIOR ANTI-CORROSIVE PAINTS

- AMERON 133/333
- SIGMA BT
- SHERWIN-WILLIAMS DURA PLATE
- AKZO-NOBEL INTERGARD 143

• SOLVENTLESS COATINGS

TANKS

- SIGMA EDGEGUARD AND CSF
- SHERWIN-WILLIAMS DURA-PLATE UHS
- AKZO-NOBEL INTERGARD 143

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Recent Developments (Cont'd)

NAVSEA NAVAL SEA SYSTEMS COMMAND

• LOW SOLAR ABSORBENT/ANTI-STAIN EXTERIOR TOPSIDE COATINGS

FREEBOARD AND DECKS

- NCP (NILES CHEMICAL PAINT CO.) 7229C
- AKZO-NOBEL INTERLAC 1

• BIOCIDE-FREE ANTIFOULING PAINTS FOR SPECIAL APPLICATIONS

PRIMARILY FOR ALUMINUM CRAFT

- AKZO-NOBEL INTERSLEEK

• SURFACE TOLERANT COATINGS

BILGES, WET SPACES

- EURONAVY ES 301
- ALOCIT 28.15

SEA 05M1, April 2003

COATINGS FOR THE FUTURE

NAVSEA NAVAL SEA SYSTEMS COMMAND

•SINGLE COAT PRODUCTS

- URETHANES
- POLYUREAS
- EPOXIES

•QUICK CURE PRODUCTS

- SHORT POT LIFE
- COAT-TO-USE IN 30 MINUTES
- LOW TEMPERATURE CURE

•ANTI-FOULING PAINTS

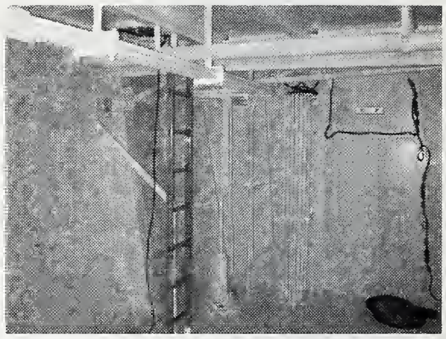
- LOW COPPER/NO COPPER
- BIOCIDE FREE
- SOLVENTLESS
- TWO COMPONENT

SEA 05M1, April 2003

Single Coat & Rapid Cure Tank Coating Systems

Improved Tank Preservation Processes

Arthur Webb - NRL



Program Team

- **Program Sponsor**
  - Office of Naval Research
- **Transition Sponsor/Materials Technical Authority**
  - Naval Sea Systems Command 05M
- **Fleet Demonstration Partners**
  - COMNAVSURFLANT, COMNAVSURPAC
  - COMNAVAIRLANT, COMNAVAIRPAC
- **Technical Development and Implementation Labs**
  - Naval Research Laboratory, Code 6130
  - Naval Surface Warfare Center, Carderock Division, Code 613

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Program Objectives

- **Develop Single Coat and Rapid Curing Coating Systems to Reduce Labor and Time Associated with Tank Preservation**
  - Replace Current 3 Coat System
  - Coating Systems with Edge Retention
  - Environmental Compliance
  - High film build in single application
  - Tanks can be returned to service quickly

  Assess performance of coating systems
  - Industrial application
  - Actual service conditions
  - Determine application limitations
- **Representative service**
  - Range of complexities
  - Multi platform applications- Amphibious, Carrier, Combatant Ships
  - Low complexity for initial installations
  - Increasing complexity as application experience increases and producibility issues are addressed
- **Tanks scheduled for preservation**
  - Select tanks in work package designated for represervation
  - Program provides funding for coating application, coating, tech assistance, and QA
  - Cost Sharing with Fleet funding for surface preparation

Background

- Definitions
  - Single Coat
    - A single application product with shorter production cycles
      - Currently employing solvent-free polyurethanes
  - Rapid Cure
    - A multiple application product with shorter cure and overcoat characteristics resulting in reduced production cycles
      - Currently employing solvent-free epoxy coatings

Cure Speed Classification

General classification of coatings based on cure times

Cure Class	Coating Chemistry
Standard Cure	Traditional solvent free epoxy
Rapid Cure	Solvent free epoxy using enhanced curing agents
Single Coat	Polyurethane and Polyurea with low catalyst levels

Typical cure times at various temperatures for coating types

Coating Type	Time to Cure				
	40F	60F	75F	90F	110F
Standard Cure (Epoxy)	No curing	12-24 hrs	8-12 hrs	6-8 hrs	4-6 hrs
Rapid Cure (Epoxy)	8 hrs	5-7 hrs	3-4 hrs	2-3 hrs	1-2 hrs
Single Coat (Urethane)	40-60 min	20-30 min	10-20 min	5-10 min	<1 min
Polyurea	2-3 min	1-3 min	30-45 sec	5-10 sec	<5 sec

Single Coat Application

- Not a "single pass" application
  - Process is the application of a polyurethane system
    - One complete coating system during work shift
  - Operation consists of three distinct coating applications each within perspective overcoat window for product
  - Work progresses in "sections" within tank
    - When section completed, application moves to next section
    - Allows for real-time (concurrent) QA/QC

Legend

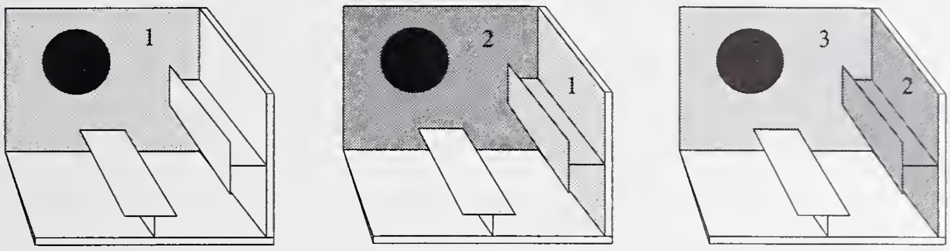
First Pass

Second Pass

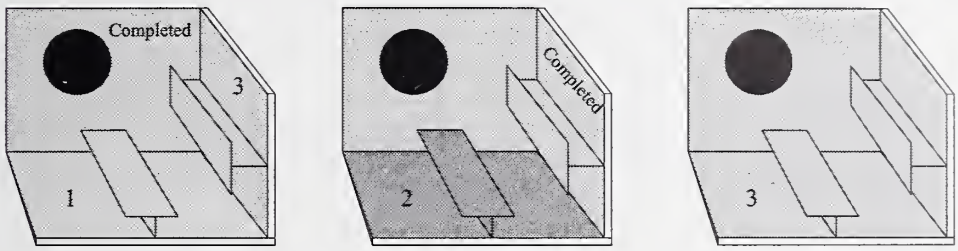
3rd Pass (Completed)

Application Sequence

Using a Single Coat System



Sequence Approach: 2-10 minutes between sections



Done!

All inclusive process, no leaving tank between subsequent coats

Current Single Coat Candidates

Polyurethane Systems

- Futura Protec II PW-ER
  - MIL-PRF-23236 testing completed, passes all tests
    - SW, Fuel, Comp Fuel, CHT, PW
- Futura Futurathane 527
  - Initial MIL-PRF-23236 testing underway
- Madison Chemical Industries Corrocote II
  - Progressing with 23236 laboratory qualification
    - SW, Fuel, Comp Fuel, CHT, PW
    - Edge retention of first and second versions failed
    - 4th version ER under review
    - Product not yet qualified

Current Rapid Cure Candidates

- Sherwin-Williams Fast-Clad
  - Progressing with 23236 laboratory qualification
    - SW, Fuel, Comp Fuel, CHT
    - No potable water
    - Product not yet qualified
- International Intergard 783
  - MIL-PRF-23236 testing initiated Aug 03
    - SW, Fuel, Comp Fuel
- Sigma EX 1762
  - Initial MIL-PRF-23236 qualification underway
    - Formulated for all tank applications, except potable water

Current Rapid Cure Candidates

Curing Performance for Current Fast Cure Candidates

Properties	SIGMA EX1762	SH-WMS FASTCLAD AMINE Cure Times	INTERNAT INTERGARD 483/783
SET TO TOUCH	1.3 hrs	1.6 hrs	1.4 hrs
TACK FREE	1.9 hrs	2.3 hrs	2.3 hrs
DRY HARD	2.1 hrs	2.6 hrs	2.5 hrs

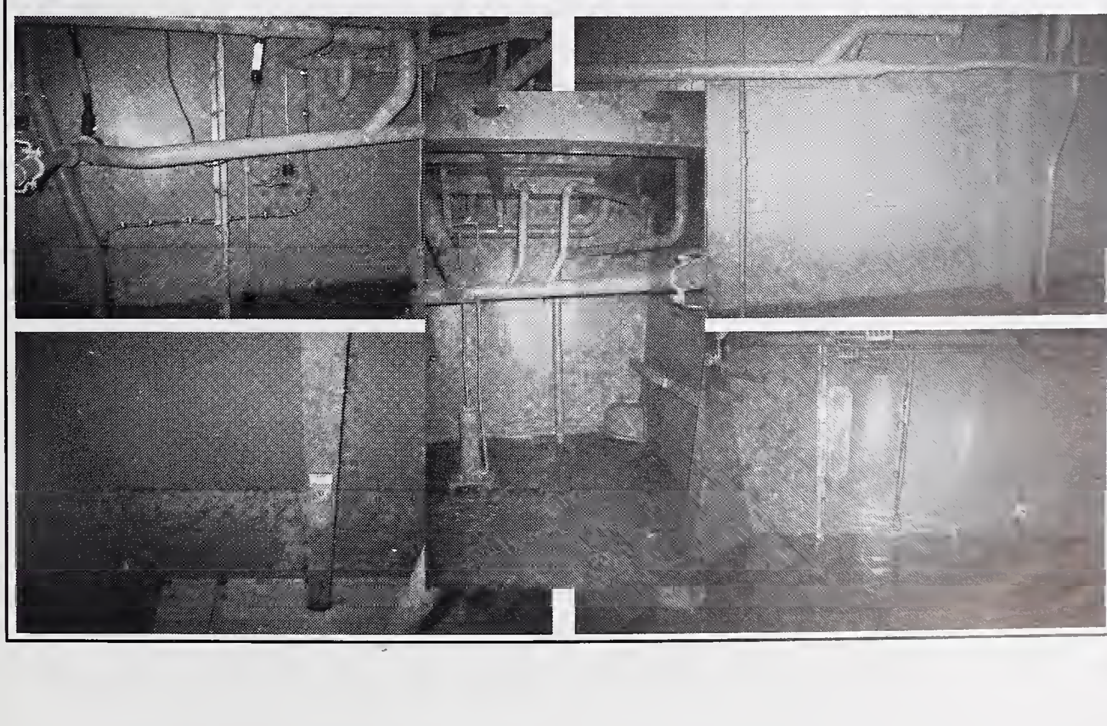
ND= no difference or change from dry hard reading coatings were cured through at the dry hard measurement time

Single Coat Demonstrations

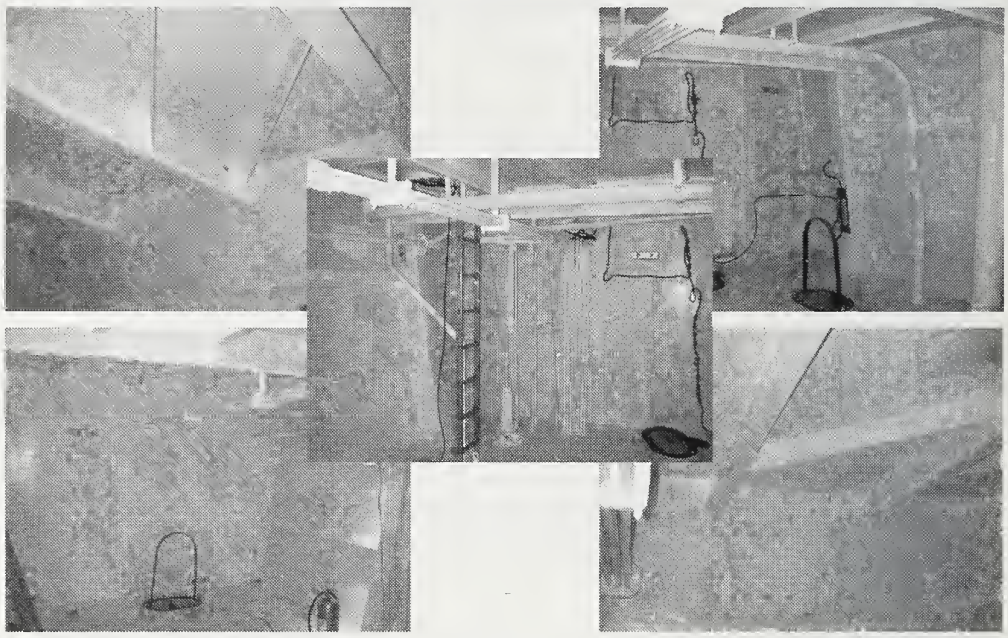
- **USS GUNSTON HALL (LSD-44) May 2002**
  - Madison Marithane
  - 1 Tank: 3-121-1-W
- **USS WHIDBEY ISLAND (LSD-41) Aug 2002**
  - Madison Marithane
  - 2 Tanks: 3-129-1-W & 3-103-1-W
- **USS GEORGE WASHINGTON (CVN 73) June 2003**
  - Madison Marithane
  - 1 DC Void: 3-123-1-V
- **USS TORTUGA (LSD-46) Nov 2003**
  - Futura Protec II
  - 1 Tank: 5-140-1-W
- **USS ASHLAND (LSD-46) Jan 2004**
  - Futura Potable Water
  - 2-Tanks: 6-41-1-W & 6-41-3-W

Successive demonstration of same product involves tanks with progressively higher complexity and size

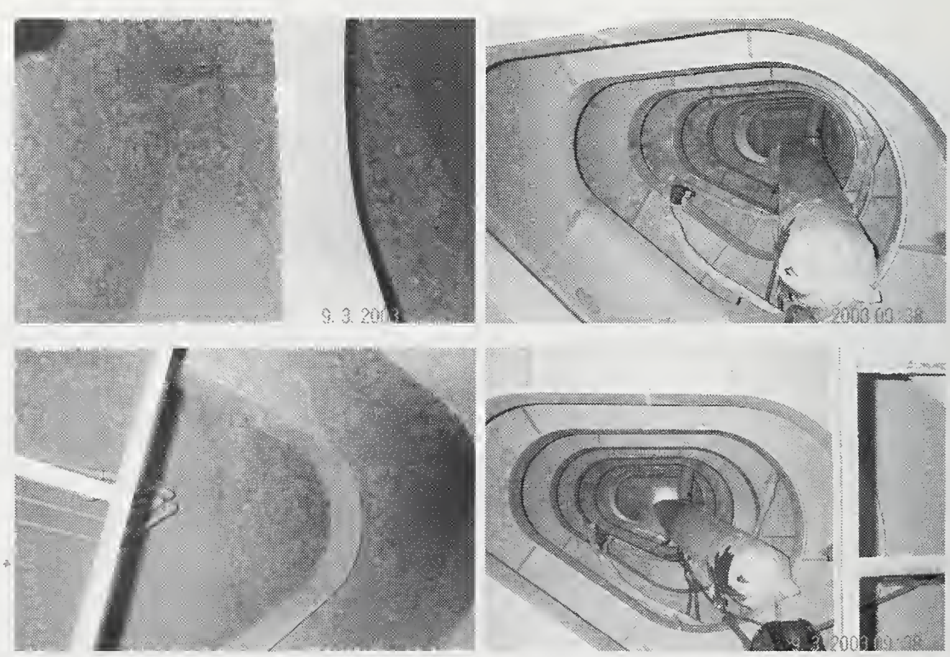
USS GUNSTON HALL LSD-44, Single Coat Application
Insertable Stalk Inspection Sys (ISIS) Coatings Assessment Images
In-Service Inspection, 6 months



USS WHIDBEY ISLAND LSD-41, Single Coat Application
Aug 2002 PMA, NORSHIPCO VA
Seawater Ballast Tank 3-129-1-W & 3-103-1-W
Application of Madison Marithane II Ultra Polyurethane



USS TORTUGA LSD-46, Single Coat Application
Futura Protec II applied in Tank 5-140-1-W , September 2003



Rapid Cure Demonstrations

- **USS WASP (LHD-1) June 2003**
  - Sherwin-Williams Fast Clad
  - 1 Tank: 5-104-1-W
- **USS TORTUGA (LSD 46) Nov 2003**
  - Sherwin-Williams Fast Clad
  - 2 Tanks: 5-125-1-W, 5-129-1-W
- **USS ASHLAND (LSD-46) Jan 2004**
  - Sherwin-Williams Fast Clad
  - 4-Tanks: 3-98-1-W, 3-103-2-W, 3-129-2-W, 5-129-2-W

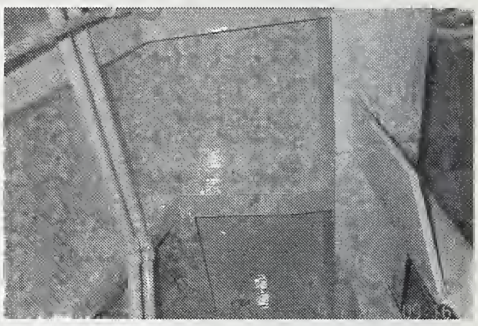
- Successive demonstration of same product involves tanks with progressively higher complexity and size

USS WASP LHD-1, Rapid Cure Application

Sherwin-Williams Fast-Clad applied in Tank 5-140-1-W , 12 June 2003

USS TORTUGA LSD-46, Rapid Cure Application

Sherwin-Williams Fast Clad applied in Tank 5-129-1-W , September 2003



Demonstration Process Requirements

- Surface Preparation
  - SSPC SP-10
    - Conductivity <30mS/cm
    - Profile 2-4 mils
  - Environmental Control
    - 50% RH maximum
    - Dew point and ambient temperature >5° difference
  - Certified applicator
    - Completed training and demonstrated proficiency *prior* to commencement of job
  - Coating application
    - Holiday inspection on all angles and flange backsides
    - Development of optical holiday detection techniques

Lessons Learned

- Single Coat systems exhibit propensity for rapid turn-around
  - Tank can be completely coated and finished in one day
  - Applicator training is absolutely essential
    - Urethane systems less user friendly
    - Requires plural pump and dual feed or impingement mix gun
    - Coating is susceptible to moisture during application
- Rapid cure systems allow for reduced maintenance cycle
  - Painting cycle time can be significantly reduced
  - Applicator training less critical but necessary for plural component usage.
    - Epoxy-based systems more user friendly
    - Uses plural pump with single feed guns
    - Less affected by moisture during application

Lessons Learned

General Product Selection Guidelines

General Guidelines for Single Coat and Rapid Cure Coatings Installation					
Tank Size (ft^2)	Tank Complexity	Temperature	Coating System	Set Time	Overcoat Window
<5000	Low	50 to 90F	Single Coat	20-30 min	4 hrs min
<5000	Med	50 to 90F	Single Coat	30-40 min	4 hrs min
<5000	High	50 to 90F	Rapid Cure	40-60 min	4 hrs min
>5000	Low	50 to 90F	Rapid Cure	3 hrs	8 hrs min
>5000	Med	50 to 90F	Rapid Cure	3 hrs	8 hrs min
>5000	High	50 to 90F	Rapid Cure	3 hrs	8 hrs min
<5000	Any Configuration	>90F	Rapid Cure	3 hrs	8 hrs min
>5000	Any Configuration	>90F	Rapid Cure	3 hrs	8 hrs min

Need for Improvement

- Single coat polyurethanes
  - Curing speeds extremely attractive
    - Low temperature capabilities also of interest
  - Solvent free formulations ideal for shipbuilding and repair
  - However current polyurethane systems not ideally suited for marine and industrial application environment
    - Poor control of overcoat windows
    - Susceptible to application errors
    - Can exhibit limited adhesion
    - Limited chemical resistance (fuel and alkaline conditions)
    - Corrosion inhibition properties can unpredictable
  - Formulation difficulties
    - Limited raw materials base (resins)
  - New resin technologies needed
    - Need corrosion inhibition, chemical resistance and adhesion of amine-cured epoxies with the rapid cure properties of a polyurethane

New Technology

- NRL Novel Resins
  - Functional polyol resins synthesized from current widely available raw materials
  - Solvent free
  - Cured using all commercial isocyanates
    - Aromatic for chemical resistance
    - Aliphatic for weatherability

Background

- Current high solids and solvent free polyurethanes
  - Polyether polyol blends
    - Low viscosity
    - Moderate moisture absorption (polyether backbone)
    - Low to medium isocyanate demand
    - Chemical resistant linings using aromatic isocyanates
  - Low molecular weight acrylic or polyester polyols
    - High viscosity
    - Moderate moisture absorption
    - Poor alkaline resistance (acrylic side chains & ester backbone)
    - Low isocyanate demand
    - Used for weatherable coatings (aliphatic isocyanate cured)

Novel Resins

- Modified aliphatic backbone
  - Alkaline resistance
  - Low moisture pick up
- Primary and secondary hydroxyl functionality
  - Primary OH for reaction
  - Secondary OH for adhesion
- Solvent free
  - Low and medium viscosity
- Medium to high isocyanate demand
  - Enhanced chemical resistance (aromatic isocyanate)

Standard Features

- Solvent free
  - Requires no solvent during manufacturing
- Rapid cure system
  - ~30 Minutes @ 25C
- Instant cure system
  - < 1 minute @ 25 C
- Variable Viscosity
  - < 100 Cps for weatherable systems
  - 10,000 Cps for chemical resistant systems
- High adhesive strength
  - >2000 psi

Special Features

- Zero VOC
  - No solvents employed in manufacturing or application
- Variable functionality
  - Equivalent weights ranging from 76 to 250
- Gloss retention
  - Comparable to acrylic polyurethanes
- Chemical Resistance
  - Comparable to current epoxies
- Rapid cure capability
  - Controllable via structure and catalyst levels

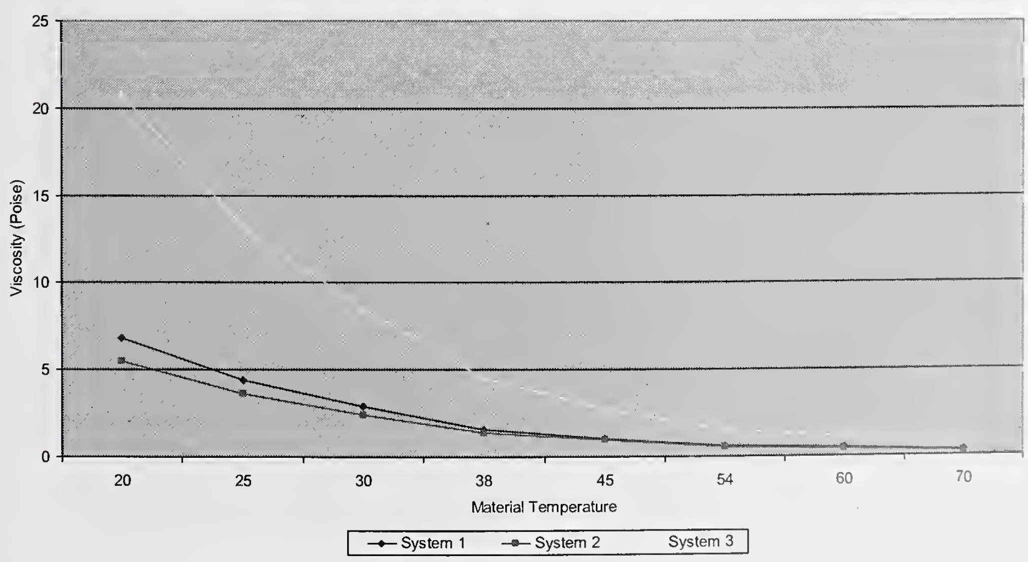
Physical Properties

Comparative Properties of NRL Resin Systems

Novel Resin Comparative Properties			
System	Description	Target Use	Viscosity (Centipoise)
1	Aliphatic Trifunctional polyol	Exterior coatings	400-450
2	Aliphatic Trifunctional polyol	Clear coat and reactive diluent	300-325
3	Aliphatic pentafunctional polyol	Medium duty immersion	1800-2000
4	Aliphatic Trifunctional polyol	Medium duty immersion	1500-1800
5	Cycloaliphatic tetrafunctional polyol	Medium duty immersion	3500-3800
6	Aromatic tetrafunctional polyol	Heavy duty immersion	10000-15000

Physical Properties

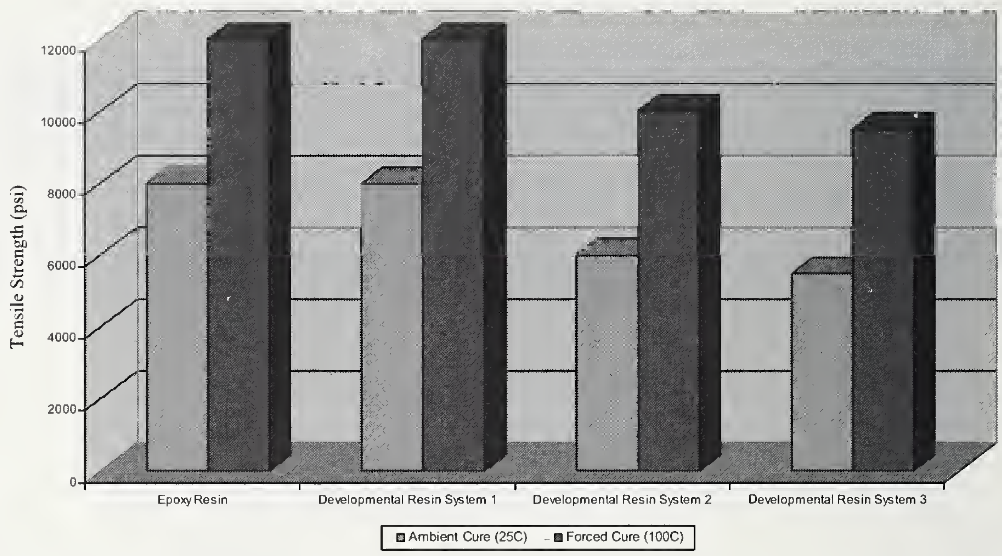
Viscosity vs. Temperature for 3 Systems*



* Constant shear rate of 1333 s

Mechanical Properties

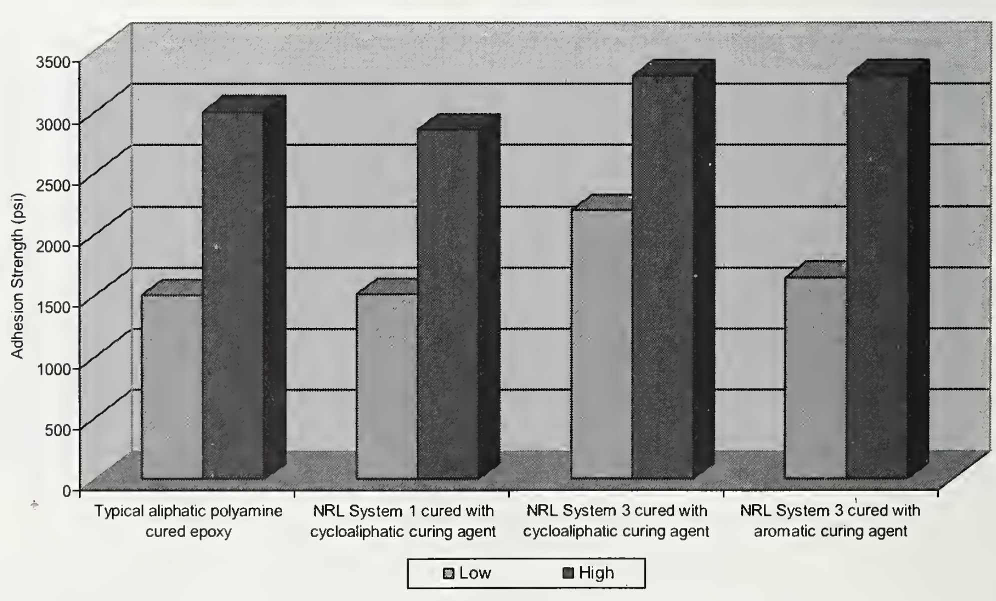
Effect of Post-Cure Baking 1 hr @ 100C
Tensile Values of NRL Resins Compared to Epoxy*



* Bis-A Epoxy cured with aliphatic polyamine

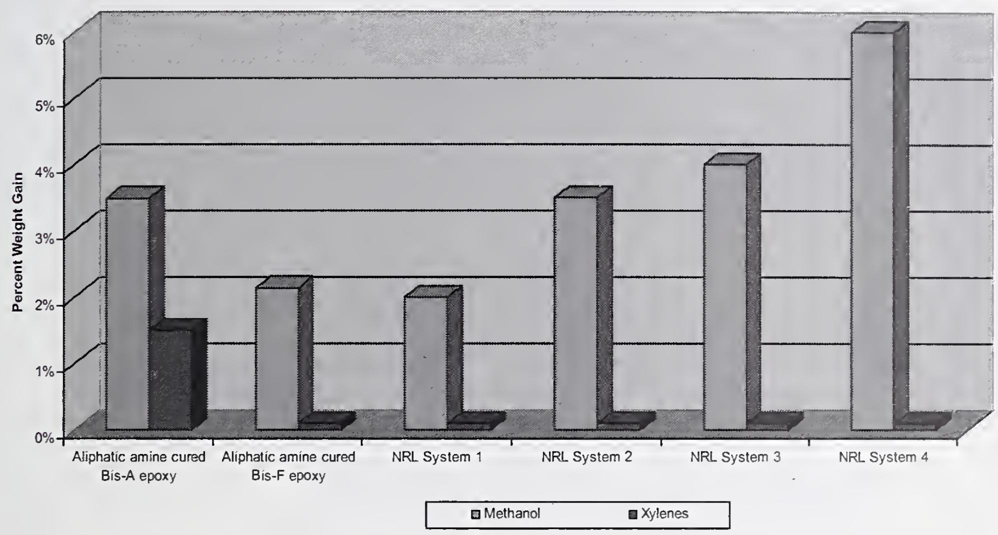
Adhesion Performance

Comparison of NRL Systems to Commercial Epoxy



Chemical Resistance

Methanol and Xylene Resistance Compared to Commercial Epoxy Systems



Weathering Resistance

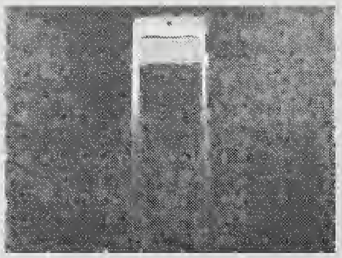
Systems Cured with Desmodur N3600

Date	Tile ID	Gloss	Designation	L	a	b	▲ e
04/22/03	System 3		STANDARD	74.4	-0.97	6.7	
04/22/03		85	UNTESTED	74.6	-0.96	6.7	0.11
04/28/03		88	100 HOUR QUV	70.1	-1.9	30.6	24
05/05/03		90	200 HOUR QUV	69.4	-1.2	34.9	29
05/12/03		89	300 HOUR QUV	68.8	-0.58	37.8	32
04/22/03	System 2		STANDARD	72.9	0.39	2.8	
04/22/03		85	UNTESTED	72.7	0.39	2.8	0.22
04/28/03		91	100 HOUR QUV	69.1	-2.3	25.4	23
05/05/03		86	200 HOUR QUV	68.4	-2.1	29.9	28
05/12/03		96	300 HOUR QUV	68.3	-1.84	32.5	30
04/22/03	System 1		STANDARD	74.1	0.75	2.6	
04/22/03		77	UNTESTED	74.3	0.77	2.6	0.19
04/28/03		70	100 HOUR QUV	71.5	-2.7	22.1	20
05/05/03		73	200 HOUR QUV	71	-2.4	24.5	22
05/12/03		87	300 HOUR QUV	71.6	-2.21	27	25
04/22/03	System 4		STANDARD	75.9	0.67	3.3	
04/22/03		90	UNTESTED	76.1	0.67	3.2	0.13
04/28/03		85	100 HOUR QUV	72.2	-1.9	28.4	26
05/05/03		88	200 HOUR QUV	71.1	-1.3	33.7	31
05/12/03		90	300 HOUR QUV	70.5	-0.37	36.9	34.1

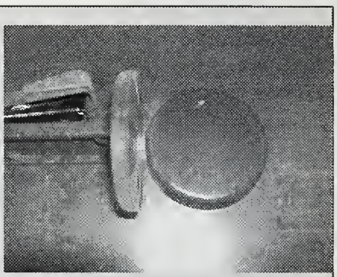
Note: no light stabilizers added

Targeted Uses

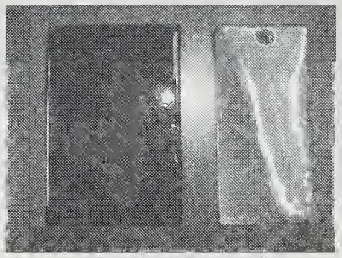
Solvent Free Rapid Cure Nonskid



Solvent Free Exterior Topcoat



Casting Resin and Thermal Barriers



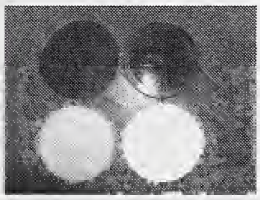
Solvent Free Tank Lining

Comparative Properties

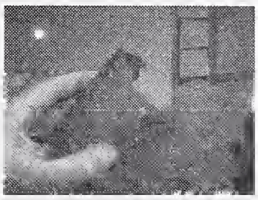
- NRL System Design Features
  - Good color and gloss retention
    - Solvent free aliphatic topcoat
  - Good hydrocarbon fuel resistance
    - Solvent free aromatic system
  - Excellent direct to metal adhesion (self priming)
  - Good cathodic disbondment resistance (hydrolytically stable)

Coatings Formulation

- Resin system can be synthesized by any well equipped coating/resin manufacturer
  - Specialized reactors and handling equipment not required
- Compatible with most pigment materials
- Utilizes standard production processes



Accepts most pigment types



High flexibility non-skid

Summary

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